Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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PUBLIC UTILITIES
COMMISSION

William A. Bonnet
Vice President
Government & Community Affairs

December 29, 2006

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 05-0315 - HELCO 2006 Test Year Rate Case
Act 162 Supplemental Testimonies

In accordance with Order No. 23153, enclosed for filing are the original and ten copies of the supplemental testimonies of Alan K. C. Hee, Jeff D. Makholm, Gene T. Meehan and Tayne S. Y. Sekimura, and a certificate of service.

Sincerely,

William A. Bonnet

cc: Division of Consumer Advocacy
Keahole Defense Coalition, Inc.

CERTIFICATE OF SERVICE

I hereby certify that on December 29, 2006, I served copies of the foregoing supplemental testimonies, together with this Certificate of Service, by hand delivery or carrier to the following at the following addresses:

Division of Consumer Advocacy (4 copies)
Department of Commerce and Consumer Affairs
250 South King Street, Room 825
Honolulu, Hawaii 96813

Mr. Michael L. Brosch (1 copy)
Utilitech, Inc.
740 North West Blue Parkway, Suite 204
Lee's Summit, Missouri 64086

Mr. Joseph A. Herz (1 copy)
Sawvel & Associates, Inc.
100 East Main Cross Street, Suite 300
Findlay, Ohio 45840

Keahole Defense Coalition, Inc. (1 copy)
c/o Keichi Ikeda
73-1489 Ihumoe Street
Kailua-Kona, Hawaii 96740-7301

DATED: Honolulu, Hawaii, December 29, 2006.

Lyndon Haack

Lyndon Haack

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	Docket No. 05-0315
	)	
For Approval of Rate Increases and	)	
Revised Rate Schedules and Rules.	)	
	)	

HELCO
SUPPLEMENTAL TESTIMONIES
AND EXHIBITS

BOOK 1 OF 1

December 29, 2006

ST-22 A.K.C. HEE

SUPPLEMENTAL TESTIMONY OF
ALAN K.C. HEE

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Energy Cost Adjustment Clause
Energy Policy Act of 2005

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan K.C. Hee and my business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of Hawaiian Electric Company, Inc.'s Energy Services Department ("ESD").

Q. What is your educational background and professional experience?

A. My experience and educational background are listed in HECO-S-2200.

Q. What is your area of responsibility in this testimony?

A. I will address the two issues that the Commission added to this proceeding in Order No. 22903:

- Whether HELCO's ECAC complies with the requirements of Act 162.
- Whether the commission should adopt, modify, or decline to adopt in whole or in part, the standards for time-based metering and communications articulated in section 111(d)(14) of PURPA, as amended by EPAct (16 U.S.C. § 2621(d)(14)).

My testimony will cover Hawaii Electric Light Company's ("HELCO") Energy Cost Adjustment Clause ("ECAC"), including a discussion of the risk sharing properties of the Clause as it relates to the requirements of Act 162 (Session Laws of Hawaii, 2006). Mr. Jeff Makholm (HELCO ST-23) and Mr. Eugene Meehan (HELCO ST-24) discuss the ECAC's compliance with Act 162 and fuel price hedging, respectively, in more detail.

My testimony also addresses the time-based rate standards identified in the Energy Policy Act of 2005 ("EPACT 2005").

Q. Are you replacing Mr. Young as the witness in the area of the ECAC?

A. Yes. I am adopting Mr. Young's HELCO T-3 testimony on the ECAC.

ENERGY COST ADJUSTMENT CLAUSE

Act 162

Q. On June 2, 2006, the Governor of Hawaii signed into law Act 162, which amends Section 269-16 of the Hawaii Revised Statutes. How does Act 162 affect the ECAC?

A. Act 162, in part, states the following:

> Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:
> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower it fuel costs and encourage greater use of renewable energy;
> (3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
> (4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and
> (5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

Q. How has the Company approached the issue of whether HELCO's ECAC complies with Act 162?

A. The Company has selected a highly qualified consultant, National Economic Research Associates, Inc. ("NERA"), to provide assistance in evaluating the extent to which HECO, HELCO and MECO ("the Companies") currently comply with the requirements of Act 162. The consultant's final report was received on

December 28, 2006 and was submitted to the Commission on December 29, 2006.

Further, in HELCO ST-23, Mr. Jeff Makholm, Senior Vice President of NERA, explains the role of fuel adjustment clauses in utility ratemaking in the United States and analyzes whether HELCO's ECAC complies with Act 162. In HELCO ST-24, Mr. Eugene Meehan, also a Senior Vice President at NERA, discusses the possibility of HELCO engaging in fuel price hedging and assesses the potential impact of fuel price hedging on HELCO, its customers, and the regulatory ratemaking process. In HELCO ST-18, Ms. Tayne Sekimura explains the impact that potential changes to the ECAC could have on investors.

Q. Act 162 requires the design of the ECAC to consider a number of factors including fuel price risk sharing between the Company and its ratepayers. What is HELCO's position on the appropriate level of fuel price risk sharing in the ECAC?

A. It is HELCO's position that the current level of ECAC fuel price risk sharing is appropriate, and that no change is necessary to the current ECAC risk sharing approach.

The ECAC does not necessarily pass 100% of any change in fuel expenses to ratepayers. HELCO's ability to recover its fuel expenses is subject to an efficiency factor, which measures how efficiently HELCO converts fuel energy into electrical energy. If HELCO cannot meet the efficiency factor embedded in the ECAC, it recovers only a portion of its fuel expenses. Thus, HELCO is already at risk for the non-recovery of some portion of fuel expense and this risk profile is inherent in the currently employed ECAC mechanism.

The risk associated with meeting the efficiency factor is one that HELCO can address through the overhaul and maintenance of its generating units and unit commitment schedule among others. Thus, it is reasonable for the Commission to hold the Company responsible for not meeting the efficiency standard and for its fuel expenses to be subject to the risk of non-recovery as a result.

However, fuel prices are subject to market forces and geopolitical events that HELCO cannot control. A risk sharing mechanism which penalizes the Company because prices increase above an expected base price, even one which provides a symmetric positive incentive when prices are below the base, holds the Company financially responsible for events beyond its control. Such a risk sharing mechanism would place the Company in an untenable financial position, for which it is not compensated.

Therefore, HELCO maintains that the current level of ECAC risk sharing is appropriate, and that no change is necessary to the current ECAC risk sharing approach.

Q. Does HELCO have plans to explore ways to mitigate the impact of fuel price volatility on customers?

A. Mr. Makholm in HELCO T-23 has identified two rate smoothing alternatives, budget billing and fixed rate billing. HECO will explore these two concept alternatives to determine if they are appropriate for implementation at HELCO.

ENERGY POLICY ACT OF 2005

Q. Order No. 22903 added the following issue to this proceeding: "Whether the commission should adopt, modify, or decline to adopt in whole or in part, the standards for time-based metering and communications articulated in section 111(d)(14) of PURPA, as amended by EPAct (16 U.S.C. § 2621(d)(14))." How does EPACT 2005 define "time-based rate schedule"?

A. As defined by the EPACT 2005, a time-based rate schedule is a "schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level." The federal standard lists three types of time-based rate schedules that may be offered, among others:

1) Time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

2) Critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption.

3) Real-time pricing whereby electricity prices are set for a specific time period on an advance or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly.

The fourth definition in the federal standards is credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations. This is more of a load management concept, than a time-based rate schedule.

Q. What does EPACT 2005 require with respect to time-based rates?

A. EPACT 2005 requires that each State regulatory authority conduct an investigation and issue a decision as to whether it is appropriate to implement the following standards:

1) Each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

2) Each electric utility shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate.

Q. What are the intended benefits of time-based rates?

A. Time-based rates, if designed properly, are intended to provide price signals to consumers on the time-based rate schedule, so they can make decisions on when or whether to use electricity. With this pricing information, the consumer can then choose between consuming electricity now or deferring consumption to another, less costly, time period. Intended benefits of time-based rates may include reduced peak load demand, reduced total demand, increased reliability, more efficient use of current capacity, and lower consumer bills. For example, resulting reductions in peak demand may permit more expensive generators to run less often, and may also reduce the need for the addition of peaking capacity. Deferring consumption also can improve reliability by reducing the load on existing generators and purchased power providers. These benefits are only realized, however, if consumers significantly reduce their demand in response to price signals. Also, analysis and/or market tests may be used to determine if these benefits can be attained in a more cost effective manner using alternative means.

Q. If the rate design proposals in this proceeding are approved by the Commission would HELCO comply with the first standard?

A. Generally, yes. HELCO's rate proposals in this proceeding will provide a time-of-use rate schedule for each of its customer classes (except for Schedule F - Street Light Service customers, which do not have significant flexibility to shift load). Should all of the proposed voluntary time-based rates be approved, the portfolio of time-of-use rates will include:

	Time-Based Rate	Applicable Customer Class
1)	TOU-R, Residential Time-of-Use Service	Sch. R & E
2)	TOU-G, Small Commercial Time-of-Use Service	Sch. G, H
3)	TOU-J, Commercial Time-of-Use Service	Sch. J, K
4)	TOU-P, Large Power Time-of-Use Service	Sch. P
5)	Rider M, Off-Peak and Curtailable Service	Sch. J, P

As Mr. Peter Young also states in HELCO T-20 (page 42), HELCO "proposes to manage participation in these optional rates while collecting data for future time-of-use rate design offerings by setting a limit on the number of meters that can participate in each optional rate schedule. The meter limit facilitates effective implementation of these rate options since the current billing system cannot bill time-of-use rates automatically, and the Company may not have a new Customer Information System (CIS) in place by the time these proposed rates are approved. In addition, the Company has not estimated any revenue adjustment for customer participation in these time-of-use rate options, so the meter limit helps to mitigate any negative revenue impact that the Company might experience in implementing these rate options." HELCO offers a time-of-day Rider T option but is proposing to close it to new customers in lieu of the new time-of-use rates it is proposing in this proceeding.

In addition, in order to enable the customer to manage his energy use, each customer on a TOU rate schedule will be provided with a time-of-use meter so that the appropriate period pricing can be accurately billed on a monthly basis.

Q. Is HELCO investigating new metering technology?

A. Yes. Even though HELCO proposes to implement time-of-use rate options with existing metering technology, its affiliate company, HECO, continues to proactively investigate Advanced Metering Infrastructure ("AMI") solutions. For example, in October 2006, HECO agreed to partner with Sensus Metering Systems to field test the FlexNet system, which is a full two-way fixed network AMI system that delivers interval meter data. The FlexNet system can facilitate time-of-use pricing options, as well as transmit meter status information. This pilot program will include approximately 500 Sensus "smart" meters in the Honolulu area. HELCO may benefit from the work being pursued by HECO, should AMI prove to be appropriate for metering purposes.

Q. Does HELCO currently comply with the second standard?

A. Yes. For each participant in its existing or proposed time-of-use rate options, HELCO provides or will provide a time-of-use meter to record and properly reflect period pricing.

Q. Does HELCO offer other rate options that take into account the time at which energy is used by the customer?

A. Yes, as explained by Mr. Peter Young in HELCO T-20. For example, Rider M is an optional off-peak and curtailable service applicable to Schedule J customers with loads greater than 100 kW, and to customers served under Schedule P, with loads greater than 300 kW. Rider M provides load management incentives to customers by modifying the determination of the billing demand under Schedule J or Schedule P. It offers two load management service options: Option A – Off-Peak Service, and Option B – Curtailable Service.

Q. Does HELCO plan to offer any of the other types of time-based option?

A. Yes. HELCO has included a commercial & industrial load management program in its IRP-3 draft preferred plan, which would provide credits for customers with large loads who enter into pre-established peak load reduction agreements. Under the proposed load management programs, HELCO would pay incentives to customers (which can be a credit to the customers' bills) who install a load control receiver on selected customer loads. In the execution of its five-year IRP Action Plan to be filed with the Commission HELCO will re-evaluate the cost-effectiveness of the load management programs before deciding on the size of any such programs and the scheduling of their implementation.

Q. What is the status of critical peak pricing and real-time pricing, the other two examples of time-based rates included in EPACT 2005?

A. Each type of time-based rate is different and may not work the same for all consumer sectors. Most of the benefits of time-based rates will be realized only if consumers respond to price signals and can and do change their consumption patterns. As a result, it is important to understand what types of consumers are present in the market. If load is made up of consumers that are willing and able to adjust their load, then there is more potential than with unresponsive load. This means that sector composition (percent residential vs. percent commercial vs.

percent industrial, etc), the willingness of each sector to accept price risk, and the level of risk they are willing to accept, will determine the price responsiveness overall. Residential consumers may have a preference for lower risk. Large commercial and industrial consumers may be more responsive to dynamic prices. Large industrial consumers, which are not generally present on the HELCO system, may have more options to curtail load and may also have the benefit of on-site generation. Thus, time-based rates may only be appropriate for certain consumer sectors or utilities in some locations and the end decision may be that time-based rates are appropriate for some sectors or utilities but not for others.

HELCO understands that critical peak pricing and real-time pricing rate levels on the mainland are based, in part, on market prices for electricity. However, because HELCO lacks access to a wholesale market (i.e., HELCO operates a stand alone system on the island of Hawaii), a pricing signal to drive critical peak pricing and real-time pricing is not available to the Company. Thus, it is unclear at what levels HELCO's critical peak pricing or real-time pricing rates would be set. In addition, HELCO has proposed time-of-use rates for its customer classes in this rate proceeding and believes that it would be prudent to evaluate its customers' response to those rates before moving to rates that are more complicated for customers to understand. Therefore, the Company is not proposing critical peak and real-time pricing at this time.

Q. What is HELCO's recommendation regarding the time-based metering and communications standards included in the Energy Policy Act of 2005?

A. HELCO recommends that the Commission's adoption of the standards articulated the Energy Policy Act of 2005 is not necessary because:

1) The Company will comply with the standard regarding the offer of time-

based rates once the proposed rate design is approved.

2) HELCO's affiliate company, HECO, is already proactively investigating advanced metering and telecommunications infrastructure (AMI) solutions that will enhance the ability of the consumer to manage his energy use and cost. These solutions may prove to be beneficial to HELCO as well.

Q. Since HELCO generally is in compliance with the standard, does that mean that the Commission should adopt the standard?

A. No. First, as stated above, adoption of the standard is unnecessary. In addition, adoption of the standard could have unintended consequences. For example, the standard could be construed to require that street light customers be offered a time-of-use option, or that there be no initial limit on the number of meters that can initially participate.

In general, one size fits all federal standards are not the optimal method to achieve objectives such as equitable rates for electricity consumers. The purpose underlying PURPA can be met without adopting the time-based metering and communications standards. The stated purposes of the PURPA Title I standards, as enunciated in 1978, are to encourage (1) conservation of energy supplied by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers. The Conference Committee Report that accompanied the passage of PURPA in 1978 explained further that the first purpose of the Title was to foster conservation by end-users of electricity. The second purpose was directed at utilities and their use of energy and their facilities, including capital resources, and intended this to include "conserving scarce energy resources by techniques of rate reform which substitute the use of more plentiful resources produced in the United States in lieu of less plentiful resources, especially those imported into this Country." Joint Explanatory Statement of the Committee of Conference, Conference Committee Report accompanying Public Law 95-61 7 (PURPA), 1978, p. 69. Nothing further was added to the third purpose beyond what was said in the statute, that is, that it was intended to encourage equitable rates for consumers. This standard is closely tied to the first two stated purposes of PURPA, to (1) encourage conservation of energy supplied by electric utilities and (2) optimize the efficiency of electric utility facilities and resources.

PURPA did not take the primary responsibility over electric utility rates from the states. The Title I standards impose certain obligations on state regulatory commissions and give certain rights to persons to go before state regulatory commissions and state courts. However, under PURPA and its amendments, states retain primary responsibility with respect to retail electric rates. PURPA and the three purposes are intended to supplement state law, but do not override state law. Conference Committee Report, pp. 70-71. Also, states may consider other purposes as well that are not specified by PURPA. State commissions are not required to take actions that conflict with state law. The intention was to preserve the discretion of state commissions that is provided by state law - except to the extent that Title I imposes procedural requirements, such as requirements to hold hearings and consider and make a determination. Conference Committee Report, p. 71.

Section 269-16 of the Hawaii Revised Statutes ("HRS") not only encourages equitable rates for consumers. It requires rates to be just and reasonable and prohibits unreasonable discrimination between localities, or between users or consumers, under substantially similar conditions. HRS 269-16 and Chapter 6-61 of the Hawaii Administrative Rules prescribe procedures to consider utility rate proposals and to determine whether the proposed rates are just, reasonable and non-discriminatory. It is in this ratemaking process that the underlying purpose of PURPA to encourage equitable rates for consumers is met. Since such a process already exists, it is not necessary for the Commission to adopt the federal standards to encourage equitable rates for consumers. Rather, rates should be established based on the specific needs and circumstances that currently exist on this island. As I have explained above, the Company has proposed in this proceeding time-of-use rates which are appropriate for the island of Hawaii but it is not proposing critical peak pricing or real-time pricing which are not suited for this island at this time.

Q. Has the Commission previously considered whether to adopt any Energy Policy Act standards?

A. Yes. In Docket No. 94-0203, by Order No. 13387, filed July 19, 1994, the Commission instituted a proceeding to consider and determine the appropriateness of implementing the energy efficiency standards established by the Energy Policy Act of 1992 for electric utilities under PURPA Section 111. By Decision and Order No. 14454, filed January 12, 1996, the Commission concluded that it need not adopt the federal standards in order to be in compliance with Section 111 of PURPA, as amended by the Energy Policy Act of 1992.

Q. Please summarize HELCO's position.

A. HELCO has independently and proactively proposed to offer time-of-use rate options to all customer rate classes that give customers the ability to manage their electric bills by modifying their energy consumption. HECO is also investigating AMI solutions that may enable future and/or modified time-of-use rate options.

HECO's AMI research and its proposed time-of-use tariffs are consistent with the standards put forth by the Energy Policy Act of 2005. Thus, it is not necessary for the Commission to adopt the EPACT 2005 time-based rates standards.

Q. Does this conclude your testimony?

A. Yes, it does.

HELCO-S-2200

ALAN K.C. HEE

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 220 South King Street Honolulu, Hawaii 96813
POSITION:	Manager, Energy Services Department
YEARS OF SERVICE:	20 Years
EDUCATION:	MBA, University of Hawaii, 1982 BS, Civil Engineering Cornell University, NY, 1974
OTHER QUALIFICATIONS:	Registered Professional Engineer, Hawaii Civil Engineering Branch
OTHER EXPERIENCE:	Director, Forecasts Division Energy Services Department, 1995-2004 Director, Forecasting Division Rate and Regulatory Affairs Dept., 1991-1995 Planning Analyst, Forecasting Division Rate and Regulatory Affairs Dept., 1986-1991 Operations Engineer GASCO, Inc., Hilo 1982-1986 Peace Corps Volunteer Fiji Islands, 1974-1976

HELCO ST-23
DOCKET NO. 05-0315

SUPPLEMENTAL TESTIMONY OF
JEFF D. MAKHOLM, PH.D

On Behalf of
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Energy Cost Adjustment Clause

SECTION I: QUALIFICATIONS, PURPOSE, AND CONCLUSIONS

Q. Please state your name, business address and current position.

A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with its principal offices in a number of major U.S. and European cities. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116.

Q. Please describe your academic background.

A. I have M.A. and Ph.D degrees in economics from the University of Wisconsin, Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. My 1986 Ph.D dissertation is entitled "Sources of Total Factor Productivity in the Electric Utility Industry." I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q. Please describe your work experience pertinent to this proceeding.

A. My work centers on economic issues involving pricing, regulation and market issues for regulated infrastructure industries, including gas, electricity, water and telecommunications utilities, gas and oil pipelines, airports, toll roads and passenger and freight railroads. My consulting work includes the specific issues of competition, rate design, fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy. I have prepared expert testimony and statements, and I have appeared as an expert witness in many state and federal administrative and United States District Court proceedings, as well as in regulatory and judicial hearings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries. In these countries, I have drafted regulations, established tariffs, recommended financing options for major capital projects and advised on industry restructurings. I have also assisted in the privatization of state-owned gas utilities. As part of my international work, I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Over the past 25 years I have presented evidence on many ratemaking subjects, including the pass-through of fuel, purchased power and gas costs. For example, in 2005, I prepared testimony on the role of fuel adjustment clauses ("FACs") and related financial issues for Portland General Electric as well as a report summarizing the current state of FACs in the United States. I have testified on numerous occasions recently on behalf of Sierra Pacific Power Company and Nevada Power Company with respect to their natural gas hedging programs and related cost recovery. Overall, I have testified for electric, natural gas, water and telecommunications clients before the Federal Energy Regulatory Commission (the "FERC"), the Federal Communication Commission (the "FCC") and state commissions in Pennsylvania, Oregon, Ohio, North Carolina, Kansas, Illinois, New Jersey, New York, Maryland, California, Virginia, Rhode Island, New Hampshire, Texas, Indiana, Maine, Nevada, Wisconsin, Georgia and Connecticut. My current Curriculum Vitae, which more fully details my educational and consulting experience, is provided as **Exhibit HELCO-S-2300**.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by Hawaii Electric Light Company, Inc. ("HELCO") to provide testimony explaining the role of fuel adjustment clauses in utility ratemaking in the United States. On December 22, 2006, I submitted similar testimony in HECO T-21 in Hawaiian Electric Company, Inc.'s ("HECO") 2007 test year rate case (Docket No. 2006-0386). In my testimony for this proceeding, I explain that FACs are an important element in maintaining a vibrant and financially secure electric utility system that provides efficient, safe, adequate and reliable service—the benefits of which flow to customers over time. Finally, I address the compliance of HELCO's current power cost recovery mechanism, the Energy Cost Adjustment Clause ("ECAC"), with recent legislation.[1]

Q. What are your conclusions?

A. I conclude the following:

- FACs are a standard and longstanding part of US utility ratemaking.
- HELCO's ECAC is a well-designed FAC and benefits HELCO and its ratepayers.
- HELCO's ECAC complies with the statutory requirements of Act 162.
- HELCO's ratepayers benefit from a uniform treatment of fuel and purchased power costs across all Hawaiian Electric utilities.

Q. How is your testimony organized?

A. In **Section II**, I discuss the historical context of and the economic and ratemaking rationale behind FACs and provide a brief description of the current status of power cost recovery in the United States, focusing mainly on traditionally-regulated (as opposed to restructured) states. In **Section III**, I evaluate HELCO's ECAC in terms

[1] A Bill for an Act Relating to Energy, S.B. No. 3185, S.D. 2, H.D. 2, C.D. 1, Act No. 162, signed into law by the Governor of Hawaii on June 2, 2006 (herein after, "Act 162") amended Section 269-16 of the Hawaii Revised Statutes to include a subsection (g) that specifies requirements for the design of "any automatic fuel rate adjustment clause," of which the ECAC is one.

of the five specific requirements established by Act 162. **Section IV** concludes with a discussion of power cost "risk sharing" mechanisms.

SECTION II: BACKGROUND ON FUEL ADJUSTMENT MECHANISMS

A. Three Reasons for Fuel Adjustment Mechanisms

Q. What accounts for the common use of FACs?

A. FAC mechanisms (and other cost-adjustment mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases—called "regulatory lag"—can increase. The three classic reasons for an FAC include:

1) The purchased item (most commonly fuel) is outside the control of the buying utility.
2) *The item is a significant or large component of the utility's total operating* costs.
3) The cost changes with respect to that item can be volatile and unpredictable.[2]

It is not necessary that individual cost items be large, volatile and unpredictable to qualify for FAC treatment. An effective FAC covers all purchased energy costs, including renewable sources, on an equal footing.

Q. Please explain the first reason to support an FAC.

A. Utilities procure fuel from markets and would normally not have the ability to control the price set in those markets. The 1991 NRRI Report notes that "[u]nless a utility is vertically integrated so that it owns the fuel source (whether it is the coal mine, gas well, or others), it is unlikely that the utility can exert much control over

[2] Robert Burns, Mark Eifert and Peter Nagler. "Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets," *National Regulatory Research Institute*, November 1991, p. 9. (Hereinafter referred to as the "NRRI Report.")

the cost of the fuel."[3] Moreover, the utility does not normally have the ability to control its customers' demand. It must procure the fuel and purchased power that are needed to meet customer demand as part of its obligation to serve.

The utility, of course, has an obligation to procure its fuel and purchased power from the energy markets in a prudent manner. The NRRI Report notes that the utility is not "excused from hard-nosed, tough bargaining" and goes on to explain that state public utility commissions often hold utilities to a standard of prudent care in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause.

Given prudent management, if certain costs (called "exogenous costs") are not within the control of the utility, the pursuit of economic efficiency calls for no penalty or gain to be borne by the utility as a result of changing market conditions. Exogenous cost changes represent any change in the cost of the firm—up or down—that is beyond the control of the firm. In a competitive industry, if these costs were required to provide a service, cost changes would alter the long run marginal and average cost curves of the industry and would directly affect the market price prevailing in the industry. Because exogenous costs are not under the control of the firm, passing such cost changes through to customers automatically cannot affect the incentive of the firm to behave efficiently or the market price standard to which regulated policies aspire. The pass-through of exogenous costs permits the regulated firm's prices to reflect market conditions (for the prices of its inputs) in just the way that input cost changes affect prices in unregulated, competitive markets, while providing a market price signal to customers.

Q. Please explain the second reason to support an FAC.

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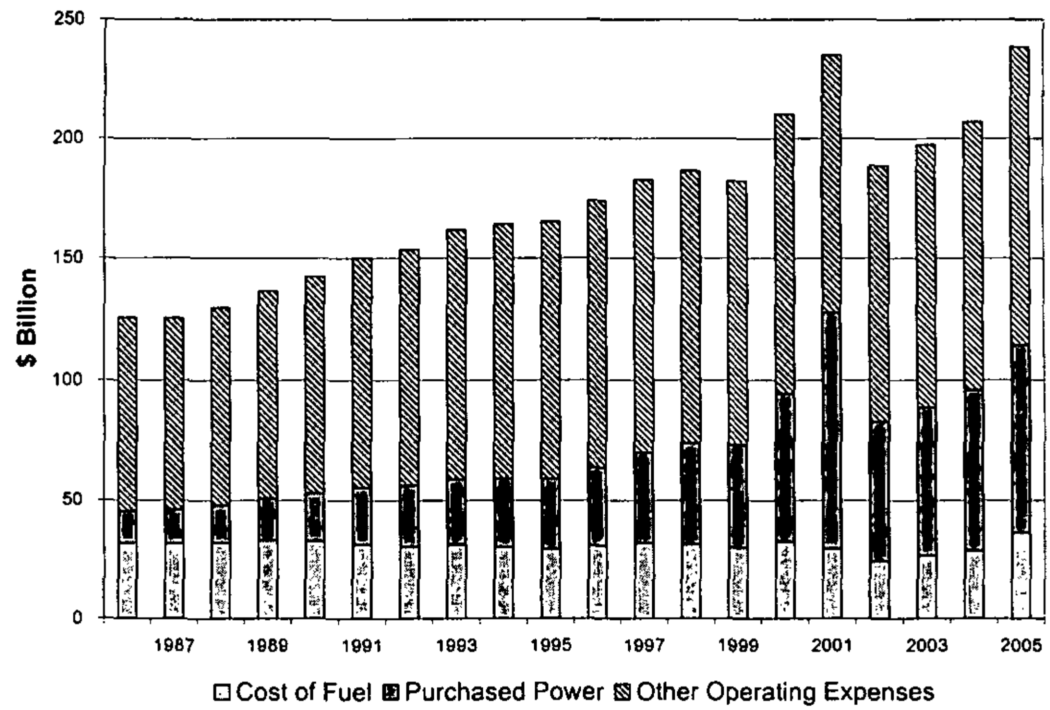
[3] NRRI Report, p. 4.

A. Fuel and purchased power costs continue to be a significant component of a utility's total operating costs. For all major investor-owned utilities ("IOUs") in the United States, the average proportion of fuel and net purchased power relative to total operating expenses ranged from 35.8 to 54.3 percent during the 1992 to 2005 period.[4] Total fuel and net purchased power averaged 40.2 percent for the 1992-2005 period, as shown in **Figure 1**. The continued high proportion of fuel and purchased power costs relative to total operating costs shows that there is a continuing role for FACs as a tool for timely recovery of fuel and purchased power costs. HECO's (including HELCO) consolidated fuel and purchased power expenditures represented about 66.8 percent of expenses in 2005, up from 64.1 percent in 2004 and 62.0 percent in 2003.[5]

[4] Energy Information Administration, Electric Power Annual 2003, p. 49, Table 8.1 Revenue and Expense *Statistics for Major U.S. Investor-Owned Electric Utilities, 1992 through 2003*, December 2004. *See*: http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf (Accessed on December 18, 2006).

[5] Hawaiian Electric Industries, Inc./Hawaiian Electric Company, Inc., SEC Form 10-K for the period ending December 31, 2005, p. 62.

Figure 1. Fuel and Net Purchased Power Costs and Other Operating Expenses for U.S. Investor Owned Utilities, 1986-2005 [6]



Q. Please explain the third reason to support an FAC.

A. Changes in fuel and purchased power costs can be volatile and unpredictable. Although HELCO is isolated from the wholesale electricity and natural gas markets, its primary source of fuel and purchased power expenses are dependent upon the market price for oil, which constitutes about 78.1 percent of HELCO's fuel mix.[7]

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[6] Energy Information Agency. *Electric Power Annual, Vol. II.* "Revenue and Expense Statistics for Selected Investor-Owned Electric Utilities": Table 8.1 (1992-2005), Table 11 (1990-1994), Table 34 (1986-1990).

[7] HECO website, About Our Fuel Mix, Available at: http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed December 7, 2006).

State commissions continue to cite the unpredictable nature of fuel and purchased power costs that, if unaccounted for, would leave the utility to bear the burden and financial risk of volatility. For example, the Louisiana Public Service Commission states that the "Fuel Adjustment Clause mechanism...has been established due to the materiality and historical and potential volatility of these costs."[8]

A utility must serve its customers under all weather and energy market conditions and therefore must purchase fuel and power to satisfy demand during peak periods during the year (*i.e.*, unusually cold winter days or warm summer days). Recent history has shown that events outside a utility's control can increase the volatility of oil, purchased power and other fuel prices.

B. Current Status of FACs in U.S.

Q. What is the current status of power cost recovery in the United States?

FACs are prevalent throughout the U.S. Of the 32 traditionally regulated states, only Utah and Vermont lack FACs.[9] Many states have instituted state-wide FAC mechanisms available to all electric (or gas) utilities. Some states have dealt with each utility on a case-by-case basis, which has led to inconsistencies across utilities within these states regarding power cost adjustments. In Hawaii, each of the utilities operate under a similar fuel clause, the ECAC. **Figure 2** summarizes the current status of FACs.

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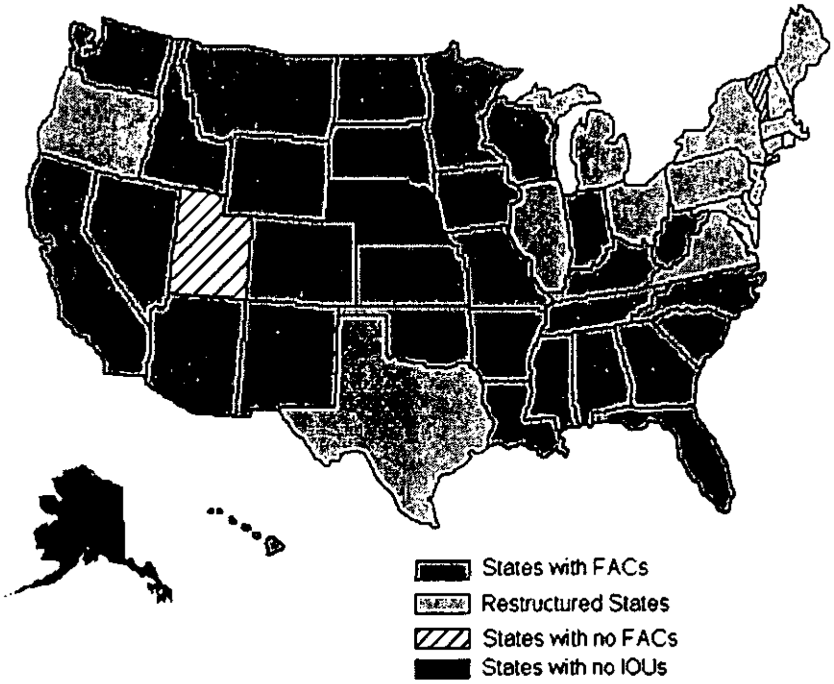
[8] Before the Louisiana Public Service Commission, "Development of standards governing the treatment and allocation of fuel costs by electric utility companies," General Order, Docket No. U-21497, October 1, 1997.

[9] Most electric restructuring states have implemented some mechanism to pass through Provider of Last Resort ("POLR") or Standard Offer Service ("SOS") charges.

Figure 2. Current Status of Fuel Cost Adjustments in the U.S.



C. Historical Context

Q. How did FACs become a common regulatory practice in the U.S.?

A. FACs were initially established as a response to specific shocks, such as high coal prices following World War I and inflation following World War II.[10] By the late 1950s, FACs were commonplace, albeit infrequently used for actual rate changes due to relatively stable input costs. The OPEC oil crisis of 1972-73, however, put FACs back in the spotlight. Following the energy crisis of 1972-73, state commissions paid increased attention to FACs. In terms of FAC design issues, the focus of at least 29 states was on uniformity so that all utilities in a state would be

[10] Michael Schmidt provides a useful summary of the early history of FACs. See: Michael Schmidt, *Automatic Adjustment Clauses: Theory and Application* (East Lansing, MI: MSU, 1980), pp. 10-11.

able to change their fuel rates using the same approach.[11] By 1990, forty jurisdictions had long-standing FACs in place.[12] In Hawaii, an oil cost recovery charge has been in place since at least the 1920s.[13]

D. Description of HELCO's ECAC

Q. Have you examined HELCO's current FAC mechanism, the ECAC?

A. Yes.

Q. What did you find?

A. HELCO's fuel and purchased power mechanism follows the same cost recovery formula as its larger affiliate, HECO, whose ECAC includes both fuel and purchased power costs. It computes the monthly weighted average of the various fuel and purchased power costs based on fuel mix, which is then converted to a rate for customers based on the estimated MWh sales for the month. The ECAC uses an efficiency factor (measured in MBtu/kWh) to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated. The ECAC contains a quarterly reconciliation for the previous quarter's actual experienced fuel and purchased power expenses on a per kWh basis relative to the forecasted amounts. This reconciliation ensures the timely recovery of fuel and purchased power costs for HELCO.

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[11] Michael Schmidt, Automatic Adjustment Clauses: Theory and Application, (East Lansing, MI: MSU, 1980), p. 87.

[12] NRRI Report, p. 9.

[13] The Hawaii Electric Co.'s tariffs for 1928 show that "[t]he rates set forth in this schedule are based on the cost to the Company of fuel oils delivered in the Company's tanks at Two Dollars ($2.00) per barrel. For each advance of one whole cent per barrel in excess of $2.00 per barrel of fuel oil, an additional charge of $0.00004 per kWh will be made for all current supplied in excess of 5000 kWh per month." A similar reduction occurred if oil prices dropped. *See*: Tariffs for The Hawaii Electric Co, Ltd. Revised Sheet No. 53, Issued July 1, 1928, Schedule P-1.

Q. How would you compare HELCO's ECAC to the power cost recovery practices of the rest of the United States?

A. The ECAC compares well to the FACs that are used in traditionally-regulated jurisdictions in the U.S. Nearly all traditionally regulated and most restructured states have some similar mechanism for power cost recovery with complete fuel cost recovery. In **Section IV**, I will discuss the few cases where the FAC mechanism does not fully pass through fuel and purchased power costs. Like the ECAC, most (about 22) of the 30 traditionally regulated states with fuel clauses have some form of true-up mechanism to reconcile actual and forecasted cost recovery. Also, about 13 of those same states have rate adjustments on a quarterly or more frequent basis.

SECTION III: ECAC'S COMPLIANCE WITH ACT 162

Q. Please describe the new requirements for Automatic Fuel Rate Adjustment Clauses outlined in Act 162.

A. Act 162 incorporates five requirements for the design of any public utility automatic rate adjustment. Act 162 requires that any automatic rate adjustment be designed to:

1. Fairly share the risk of fuel cost changes between the public utility and its customers;
2. Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;
3. Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts;
4. Preserve, to the extent reasonably possible, the public utility's

financial integrity;

5. Minimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.[14]

I now consider the ECAC's compliance with each of these requirements.

A. Fair Risk Sharing of Fuel Cost Changes

Q. What is the "risk of fuel cost changes?"

A. The risk of fuel cost changes comprises two things:

- Changes in the *price* of fuel as a single productive input; and,
- Changes in the *cost* to deliver and produce electricity from HELCO's fuel inputs. This reflects any changes in the technical ability of the utility to turn purchased fuel into electricity, which may require HELCO to purchase a greater *quantity* of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

Q. How should the risk of changes in the *price* of fuel as a productive input be "fairly shared?"

A. Fair risk sharing occurs when the utility has the means to control a cost and it has a corresponding incentive to do so (*i.e.*, it shares the risk associated with that cost). It is not economically efficient to impose risk of cost recovery on the utility when the utility is not able to control the cost. This distinction is critical because the *price* of fuel is, realistically, beyond the control of the utility. HELCO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased power costs should recognize this fact.

[14] Section 269-16(g) of the Hawaii Revised Statutes as revised by Act 162, pp. 17-18.

Under the ECAC, exogenous changes in fuel *input* costs are passed fully onto consumers. In fuel markets (as in other markets where HELCO is a price taker – service vehicles, for example), it is straightforward to demonstrate prudent purchasing. There is a well-defined market price and a well-defined need to buy from this market (*i.e.*, ratepayers' demand for electricity). In a price-taking market, imposing price change risks on the utility would lead to no efficiency gains resulting from management incentives to minimize costs. This supports the utility's ability to maintain its financial viability, and would increase regulatory lag—the time between rate cases—for costs that *are* within the utility's control, which would enhance the utility's incentive to control its base rate costs.

Q. Please describe the risk of changes in the *cost* to deliver and produce electricity from HELCO's fuel inputs.

A. The ECAC, with its "heat rate" efficiency factor, provides a partial pass-through of fuel costs. It shares the risks and/or benefits of increased plant operating efficiency by tying HELCO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has some managerial control, while also allowing HELCO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel and purchased power. HELCO has considerable control over the operation of its plants—limited by engineering realities—and therefore it is reasonable, as the Commission already does, to provide HELCO with an incentive to improve its operating efficiency to manage or lower its fuel costs.

The general role that management plays in an investor-owned utility should be recognized. Efficient and prudent management strives to minimize the amount of inputs while maximizing the production of the final product – safe, adequate and reliable service at the lowest reasonable cost. Viewed from this perspective, management *should* have an incentive to manage efficiently the selection of inputs (of which fuel and purchased power are two of many)—and HELCO does have this incentive.

This heat rate efficiency factor properly assigns the risk of changes in the cost to deliver and produce electricity from HELCO's fuel inputs to HELCO's management, while allowing changes in the price of fuel to be passed through to ratepayers.

Q. Are plant performance and heat rate targets used in other jurisdictions?

A. Yes. State commissions in Florida, Louisiana, and North Carolina are examples of jurisdictions that have established specific incentives for power plant performance.[15] A "Generating Performance Incentive Factor" is included in fuel and purchased power recovery clauses in Florida, which rewards the utility (up to a 25 basis point spread) when generation assets achieve certain performance benchmarks in availability and heat rate.[16] In North Carolina, the allowed level of fuel-cost recovery is linked to achieved nuclear capacity factors.[17] These are reasonable approaches, which provide the utility an incentive to improve plant performance, something that it does have considerable control over.

Q. What are the potential costs associated with improperly assigning power cost recovery risk to the utility?

A. Doing so could harm the utility's financial health, its credit rating and its ability to raise capital from the financial markets. Accordingly, if a utility only partially

[15] Regulatory Research Associates, Alternative Ratemaking / Incentive Ratemaking, February 15, 2005.

[16] *Id.*

[17] *Id.*

recovers its power costs through its FAC, investors will require a higher return on their capital to reflect the riskier investment.[18] While a partial pass-through of power costs may initially reduce the level of rates when unexpected fuel price increases occur, it will ultimately lead to higher costs to consumers. I discuss the regulatory history of power cost risk sharing mechanisms in **Section IV**.

B. Utility Incentives for Fuel Costs and Renewable Energy

Q. What is the second condition required by Act 162?

A. Act 162 requires that automatic rate adjustment mechanisms be designed to "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy."

This condition is closely tied to the previous one. HELCO's targeted efficiency factor promotes productive fuel use decisions and gives HELCO an incentive to reasonably manage or lower its fuel costs.

If HELCO achieves more efficient plant performance than the level of the efficiency factor (currently set at 0.14629 Mbtu/kWh), then it sees a reward. If it fails to meet this target for some reason, then it would not be able to recover the additional purchased fuel expenditures required to produce the kWhs.

Q. Should all purchases of fuel and electricity (renewable and non-renewable) be on an equal footing?

A. Yes. The ECAC should cover all purchased energy costs, including renewable sources, on an equal footing within the cost recovery mechanism. Renewable energy resources can be part of a utility's power procurement to the extent that they are cost-efficient, reliable and represent a diverse source of generation relative to the

[18] A utility's cost of equity is set based on a comparable group. Nearly all utilities have cost-recovery mechanisms in place.

traditional non-renewable resources. Like many utilities, HELCO creates and follows an Integrated Resource Plan ("IRP"), which determines the extent of renewables used in HELCO's fuel mix.

The IRP process balances cost-minimization with resource diversity and other concerns. Like purchasing fuel oil from the oil markets, purchasing energy from renewables is not without risks. To ensure the efficient use of renewable resources, the ECAC would cover all purchased energy costs, including renewable sources, on an equal footing. Currently, the ECAC is adjusted each month for changes in the energy mix of the sources of fuel and purchased power. Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy. The encouragement of renewable energy above and beyond a treatment paralleling non-renewables (*i.e.*, direct subsidization) is a matter of public policy and should not be confused with energy cost recovery.[19]

Q. Could a frequently updated and well designed FAC mechanism support renewable resource development?

A. Yes. The ECAC has positive financial implications and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. Because the utility serves as a counter-party for renewable energy companies, the credit standing of a utility frequently serves as an important determinant of renewable energy projects' ability to raise capital, and thus, improve reliability and resource diversity. Weakening the utility's credit rating through partial power cost recovery could harm renewable resources that rely on utility counter-party credit to support their investments.

[19] Purchased capacity costs of renewable resources are not recovered through the ECAC. A separate cost recovery mechanism is used for these costs.

Q. Act 162 is concerned specifically with the incentive structure facing utilities. Is this the only set of incentives a regulator should evaluate?

A. No. Just as it is proper in the pursuit of economic efficiency for utilities to have incentives to efficiently manage costs over which they have control, economic efficiency is also served if ratepayers have a cost-based price signal. Ratepayers will not choose to consume an efficient level of electricity it they are shielded from the true costs of producing electricity, and a timely FAC therefore has an important role to play in transmitting these price signals. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they may reduce their demand when the price outweighs the benefit of consuming the product. Braulio Baez, the Chairman of the Florida Public Service Commission states in a Consumer Bulletin concerning fuel price adjustments:

The action of removing fuel costs from base rates had the effect of reducing fluctuations in base rates. Both the utilities and their customers now had a better incentive to respond to fuel price changes. Because non-fuel expenditures are more stable than fuel expenditures, utilities were not only less likely to seek base rate adjustments, but any rising costs also provided the utility with a greater incentive to use other, less expensive fuels to generate electricity.[20]

Q. What do you conclude regarding this condition?

A. I conclude that so long as the ECAC treats all sources of generation equally and allows the recovery of energy costs from all sources, it complies with this condition.

C. Management of Price Volatility

Q. What is the third requirement established in Act 162?

[20] Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004.

A. This requirement requires "the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

Q. What are the potential impacts of hedging fuel costs?

A. There are no free lunches in risk management. As discussed in Mr. Meehan's testimony, HELCO ST-24, hedging has real costs to the party that wishes to reduce its exposure to price movements.[21] In some years, ratepayers may benefit from a price hedge as prices rise, but in times when prices do not rise or fall this will not be the case. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased power expenses. Accordingly, if there is a mandate for the utility to reduce ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers.

Q. Act 162 recognizes that there are alternatives "commercially available" to customers that can mitigate price risk for customers. How can a utility mitigate the risk of fuel cost changes?

A. There are two forms of hedges:

1. Physical hedges, such as long-term supply and purchased power contracts and maintaining fuel inventories. The costs of existing contracts are included in the current ECAC computations.
2. Financial hedges. In HELCO ST-24, Mr. Meehan surveys the potential financial hedging instruments that are available to HELCO and their potential impacts.[22] Generally, financial hedges either require payment to intermediaries in cash to

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[21] Testimony of Gene Meehan, HELCO ST-24 Before the Hawaii Public Utility Commission, Docket No. 05-0315, p. 4.

[22] *Id.*, p. 19.

bear risks or otherwise pay through giving up the prospect for lower future fuel prices. If utility ratepayers are willing to pay for the additional service of hedging their price risk, the ECAC would include these costs. Currently, the ECAC allows the recovery of the unhedged fuel costs, but is unclear regarding whether financial hedging costs would be recovered in the ECAC.

Q. Are there alternatives available other than hedging price risk changes that can provide similar rate smoothing benefits to price risk hedging?

A. Yes. There are alternatives to price hedging, such as budget billing plans and fixed rate plans.

Q. What is budget billing?

A. Budget billing is an optional payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limits any negative consumer feedback and targets the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year.[23] At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan. Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers.[24] The need for a

[23] Some programs have more frequent adjustments (such as quarterly).

[24] In our survey, evidence of some form of budget billing was found in 47 U.S. states and the District of Columbia. Only Hawaii, Alaska and Rhode Island did not have a budget billing program.

budget billing plan in Hawaii may not be as large as most continental U.S. states due the relative lack of seasonality in demand.

Q. Please describe the other rate option, fixed rate billing.

A. Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays a flat bill with no reconciliation, but with a risk premium. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases.

The risk premium is necessary because fixed rate billing does present risks and additional costs to the utility. If fuel and purchased power prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, customers electing a fixed rate billing option may force the utility to hedge against a position in the market for the underlying oil commodity. If a utility offering a fixed rate or flat bill program did not hedge against this fixed price obligation, they would be effectively speculating on the fuel markets. As discussed by Mr. Meehan in HELCO ST-24, there is an inability to hedge HELCO's fuel price exposure fully. Thus, any expected costs that may result from a fixed rate billing program would increase the flat bill rate over the regular tariff structure. The risk premium should be large enough to compensate the utility for any added risks and costs on average, but during periods of rising fuel prices, a large group of ratepayers taking out a fixed rate may affect a utility's liquidity and its financial health.

Fixed rate billing may provide benefits to larger customers similar to budget billing (rate stability) with the added benefit of insulation from input cost increases. Rates will, on average, be higher for the customers who select this option.

Q. What do you conclude regarding the ECAC's compliance with the third

condition of Act 162?

A. If there is a demand from customers and/or a mandate from the Commission acting on behalf of ratepayers, then recovery of the hedging and risk premium costs associated with physical and financial hedges should be included in the ECAC. However, there are other alternatives available, such as budget billing and fixed rate billing, that may provide the benefits sought through hedging programs (rate stability), and which would not require pursuing these potentially costly options.

D. Preservation of Utility Financial Integrity

Q. What is the fourth requirement of Act 162?

A. The fourth requirement is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity."

Q. How does an FAC generally, and the ECAC specifically, preserve the financial integrity of a utility and HELCO in particular?

A. For modern utilities that operate in a world of volatile fuel prices, an FAC is critical to:

- Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.
- Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.
- Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating.[25] Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely scrutinize cost-recovery mechanisms. Credit rating

[25] Again, most of any particular utility's peers also have an FAC and therefore a lack of an FAC would increase a utility's risk relative to its peers.

agencies, for example, recognize the need for robust and frequently updated FAC mechanisms. **Exhibit HELCO-S-2301** presents a selection of statements from the three major credit rating agencies detailing the critical role of power cost recovery in their credit rating evaluation process.

- Maintain HELCO's ability to raise capital. Because oil, and other fuel expenses, are a large portion of HELCO's operational costs (see **Figure 1**), the ECAC is necessary because it allows HELCO to raise capital at a reasonable cost in good markets and bad.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. FACs permit a utility to recover its costs and assure the capital markets that the company can meet its obligations to shareholders and bondholders. Colorado provides an example of the Commission balancing the concerns of the utility and its customers. The Colorado PUC explained its long-term use of FAC mechanisms by stating that it established its FAC in order to permit rapid recovery of increased costs over which the utility has no control. The PUC recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the utility's ability to provide service.[26]

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the

[26] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."[27]

Q. What do you conclude regarding the ECAC's role in preserving HELCO's financial integrity?

A. Continuation of the ECAC would allow HELCO to more readily raise capital in the future, which will improve its ability to meet future infrastructure needs and preserve the level of service demanded by its ratepayers and the Commission. The Company recognizes this fact as the most recent 10-K states that:

> Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward-looking statements and from historical results include, but are not limited to...fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses.[28]

E. Minimize Regulatory Costs

Q. What is the fifth and final requirement established by Act 162?

A. The fifth requirement is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

Q. How does the ECAC help minimize regulatory costs and meet this condition?

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[27] Before the Arizona Corporation Commission, "In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchases Power Contract," Docket No. E-01345A-03-0437, Decision No. 67744, pp. 16-17.

[28] Hawaiian Electric Industries, Inc./Hawaiian Electric Company, Inc. SEC Form 10-K for the period ending December 31, 2005, p. 10.

A. In general, FACs are designed to reduce regulatory costs by separating the volatile fuel costs from the rate base. A prime motivation for FACs is a reduction in base rate cases. The reduction of frequent base rate cases does not reduce the Commission's oversight of HELCO's fuel and purchased power expenditures. Electricity FACs can allow for recovery of narrowly-defined categories of fossil fuel costs, nuclear fuel costs, purchased power, fuel transportation costs, and hedging costs, among others. HELCO submits calculations supporting the ECAC to the Commission for review on a monthly basis.

Q. Is there any way that the ECAC could be updated to further minimize regulatory costs and the need for frequent base rate cases?

A. To further minimize regulatory costs, regulators can see that any other cost category that meets the three criteria for an automatic rate adjustment discussed in the background section receive parallel treatment to those costs already included in the ECAC. Cost categories to consider tracking separately or including in the ECAC include the following:

- All fuel and purchased power costs,
- Purchased capacity (especially considering the discussion of renewables),
- Hedging costs,
- Environmental compliance costs, and
- Any other costs specific to the jurisdiction that meet the three criteria I discussed earlier.

The breadth of adjustment clauses is not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for other costs that are large, volatile and beyond the control of the utility. Also, adjustment and cost tracking mechanisms may be implemented to allow for the parallel treatment of similar costs categories. For example, demand-side management ("DSM") costs provide a substitute for pursuing supply-side resources. If supply-side resources are recovered under an FAC, DSM costs could be treated symmetrically, which would treat supply- and demand-side energy costs on an equal footing.

Q. How would implementing a fuel price hedging program affect the frequency of HELCO's base rate cases?

A. Currently, the ECAC does not recover hedging costs. If HELCO implemented a hedging program without the ability to recover hedging costs through the ECAC or a comparable rate adjustment mechanism, there would be a potential increase in the need to file expensive base rate cases. Hedging costs, because they are directly tied to fuel and purchased power costs, fit the three criteria established in **Section II** for an "automatic" rate adjustment. Costs that are large, volatile and generally beyond the utility's control can dramatically impact a utility's financial performance and may prevent a utility from earning its allowed ROE.

Q. Are there other ways the ECAC helps minimize regulatory costs?

A. Yes. Uniformity across the Hawaiian Electric utilities reduces the administrative and transaction costs associated with using an FAC to recover fuel and purchased power costs. Treating HELCO's ECAC separately from HECO's and Maui Electric Company, Limited's ECACs would require further and unnecessary utility and Commission resources devoted to the treatment of fuel and purchased power costs. Additionally, in HELCO ST-24, Mr. Meehan describes the potential problems that would arise if HELCO's oil price exposure was hedged separately from its larger affiliates.

SECTION IV: POWER COST RISK SHARING MECHANISMS

Q. What other ways have Commissions decided to share the risk of power cost changes?

A. Some states have adopted partial pass-through mechanisms. Note that these are some times referred to as "risk sharing" mechanisms, but that characterization is incorrect given that a utility is a price taker, and would not be able to control the price of fuel and purchased power acquired from the market. **Table 1** provides a brief overview of these mechanisms.

Table 1. State Experience with Partial Pass-Through Mechanisms

State (Utility)	Mechanism
Arizona (Arizona Public Service)	90 percent of any costs or savings relative to the base level would be allocated to customers and 10 percent is allocated to the company.
Colorado (Public Service Co. of Colorado)	Graduated sharing mechanism relative to a base level: The first $15 million is allocated 50/50. The next $15 million is allocated 75/25. Any changes above $30 million are to be recovered from or flowed back to ratepayers. The maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
Idaho (Idaho Power)	The power cost adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-ups.
Washington (Puget Sound)	Graduated sharing mechanism: PSE will absorb the first $20 million relative to the baseline, 50 percent of the next $20 million, 10 percent of the next $80 million, and 5 percent of any amount that exceeds $120 million. The WUTC also implemented a "power-cost-only rate case," so PSE can update its baseline rate to reflect power costs.
Washington (Avista)	Originally, the first $9 million is absorbed by the company (an $18 million deadband) and 90 percent of the energy cost differences exceeding the initial $9 million to be deferred for a later rebate or surcharge to customers. The parameters were modified in July 2006 to a $4 million deadband, a 50/50 sharing of energy cost differences between $4 million and $10 million and a 90/10 sharing of power costs in excess of $10 million.

Q. *What do you conclude in your analysis of the above partial pass-through mechanisms?*

A. These jurisdictions blur the distinction between risk sharing for productive purposes and risk sharing in the price-taking purchase of inputs. In other words, some jurisdictions impose risk sharing on the *price* of fuel and purchased power. However, these cases are idiosyncratic and have generally been a phase in a broad movement toward less risk imposed on the utilities involved in fuel and power purchases. In all cases where a partial pass-through mechanism is used, the fuel and purchased power costs that are not allowed recovery in the FAC are apportioned to the utility for the FAC mechanism only—the companies can file rate cases to recover these increased costs (although with the expense and uncertainty of rate cases).

Generally, the implementation of risk sharing mechanisms has represented a movement toward the full pass through of costs. In Arizona, FACs were suspended in 1989, but APS established a new one in a settlement to the 2003 rate case. Thus, APS went from zero percent pass-through to 90 percent pass-through of fuel and purchased power costs. In Colorado, Public Service Company of Colorado ("PSCO") has other adjustment clauses for DSM costs, air quality improvement costs and purchased capacity that may compensate the utility for the increased fuel and purchased power risks. In its current rate case, PSCO extended its use of its FAC, but was also granted two associated incentive mechanisms: 1) if PSCO achieves coal production greater than a benchmark target, the associated savings would be shared 80/20 with customers, and 2) PSCO would share 80 percent of savings (above a deadband) related to the purchase of economic short term energy.[29]

[29] Regulatory Research Associates, Focus Note: Public Service of Colorado, November 22, 2006.

In Idaho, Idaho Power absorbed all fuel cost changes prior to 1993, 40 percent from 1993 to 1995, and only 10 percent thereafter. Still, major fuel and purchased power cost deferrals (for later collection after contentious base rate proceedings) occurred during the 2000-01 Western Power Crisis. The story in Washington follows similar lines. Neither utility had an FAC and power costs were recoverable through base rate cases. Recent variations in hydroelectric generation supply (due to a seven year drought) increased the size of deferrals and threatened the utilities' finances. Avista filed a petition on January 30, 2006, proposing to eliminate the $18 million deadband of their Energy Recovery Mechanism ("ERM"). In a settlement, Avista's deadband was narrowed to $8 million ($4 million above and below the base level) with a 50/50 sharing of power costs between $4 million and $10 million and a 90/10 sharing of power costs starting at $10 million above or below the base level. The settlement also called on Avista to examine the cost of capital impact of the ERM, as well as the company's hedging strategy for fuel and wholesale power purchases.[30] This represents another movement towards full pass through of power costs.

The fuel mix and thus exposure (and risk) to oil market price risk of the above utilities are also dramatically different than HELCO, which relies heavily upon oil for its generation needs. **Table 2** shows that oil plays an insignificant role in these utilities' generation mix and its fuel and purchased power costs. Their large hydro, nuclear and coal resources mitigate much of their exposure to the volatile oil and natural gas markets.

[30] Regulatory Research Associates, Focus Note: Avista, July 21, 2006.

Table 2. Fuel Mix for Utilities / States with Partial Pass-Through Mechanisms

Fuel Type / Source	HELCO[1]	APS[2]	PSCO[3]	Idaho[4]	Washington[5]
Hydro	3.3%	0.0%	0.0%	46.0%	66.0%
Coal	0.0%	39.3%	45.0%	47.0%	17.7%
Nuclear	0.0%	22.6%	10.0%	0.0%	5.3%
Gas	0.0%	9.1%	38.0%	6.0%	9.5%
Oil	78.1%	9.1%	0.0%	0.0%	0.1%
Geothermal	18.1%	0.0%	0.0%	0.0%	0.0%
renewables / other	0.5%	19.7%	7.0%	1.0%	1.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Sources:

1 HECO website, About Our Fuel Mix, http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed on December 12, 2006).

2 Arizona Public Service, Generation Fuel Mix and Emission Characteristics, http://www.aps.com/_files/services/BusRates/disclosure.pdf (Accessed on December 18, 2006). Note that APS does not distinguish between gas and oil. They report that gas/oil comprises 18.2% of generation, for illustrative purposes this was split 50/50.

3 Xcel Energy Fuel Supply Sources, http://library.corporate-ir.net/library/89/894/89458/items/223379/12_6XcelUtilityWeekSECwAppendix12062006.pdf (Accessed on December 18, 2006)

4 Generation Options for Idaho's Energy Plan, presentation to the Subcommittee on Generation Resources, August 10, 2006, http://www.legislature.idaho.gov/sessioninfo/2006/Interim/energy_e3_0810.ppt#561,31,2005 Idaho Electricity Fuel Mix (Acessed on December 12, 2006).

5 State of Wahsington, Department of Community, Trade and Economic Development, Fuel Mix Disclosure, http://www.cted.wa.gov/site/539/default.aspx (Accessed on December 12, 2006).

Q. After examining these partial pass-through mechanisms and the ECAC's efficiency factor, what can you conclude regarding the ECAC's compliance with the first provision of Act 162?

A. A fuel efficiency factor is an incentive that is *targeted* at a utility's production decisions and isolates the utility's production performance. Partial pass-through mechanisms are rare and have been adopted for utilities with no existing FAC in place and should not be considered as a viable option for the sharing of fuel and purchased power costs in Hawaii.

Q. What do you conclude regarding the use of FACs?

A. Fuel prices constitute a large and volatile cost for price-taking utilities. A well-established, frequently-updated FAC is essential to maintain a utility's credit and operational viability and thereby meet the requirements of customers.

Q. Does this conclude your testimony?

A. Yes, it does.

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Dr. Makholm concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive ratemaking, and the unbundling of prices and services. Issues of market definition include assessments of mergers, including the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies and Parliamentary panels abroad.

Dr. Makholm's clients in the United States include privately held utility corporations, public corporations and government agencies. Focusing mainly in the areas of gas and electric utilities, he has represented dozens of gas distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas producers. Dr. Makholm has also worked with many leading law firms engaged in natural gas and electricity issues.

Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal—many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
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Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
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M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

1996-present	Senior Vice President. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1986-1996	Vice President/Senior Consultant. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist. National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist. Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist. Associated Utility Services, Inc., Moorestown, New Jersey.

RECENT TESTIMONY (SINCE 1994)

Before the Public Utilities Commission of Nevada, Rebuttal Testimony of Jeff D. Makholm on behalf of Sierra Pacific Power Company, Docket No. 06-05016. October 2, 2006. Subject: Prudence of gas purchase costs.

Before the Federal Energy Regulatory Commission, Reply Testimony of Jeff D. Makholm on behalf of the State of Alaska, Docket No. August 11, 2006. Subject: Relative risk and capital structure for the Trans Alaska Pipeline System (TAPS).

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Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony of Jeff D. Makholm on behalf of Sierra Pacific Power Company (Gas Division, WestPac Gas), Docket No. 06-0516. May 15, 2006. Subject: Prudence of the company's gas hedging strategy.

Before the Public Utilities Commission of Nevada, Direct Testimony of Jeff D. Makholm on behalf of Nevada Power Company, Docket No.06-1____. January 17, 2006. Subject: Prudence of the company's gas hedging costs.

Before the New Brunswick Board of Commissioners of Public Utilities, Rebuttal Testimony of Jeff D. Makholm on behalf of the Public Intervenor, Board Reference 2005-002. December 30, 2005 (original filing), January 23, 2006 (updated filing). Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony of Jeff D. Makholm on behalf of Sierra Pacific Power Company, Docket No.05-12001. December 1, 2005. Subject: Prudence of the company's gas hedging costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony of Jeff D. Makholm on behalf of Sierra Pacific Power Company, Docket No.05-9016. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony of Jeff D. Makholm on behalf of Nevada Power Company, Docket No.05-9017. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Ohio, Supplemental Testimony of Jeff D. Makholm on behalf of The Dayton Power and Light Company. Case No. 05-276-EL-AIR. September 26, 2005. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony of Jeff D. Makholm on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. May 12, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Reply Report of Jeff D. Makholm on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). April 12, 2005. Subject: Pipeline capacity valuation.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No 05-1028. April 12, 2005. Subject: Prudence of gas purchase costs.

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Before the Public Utilities Commission of the State of Oregon, Direct Testimony and Exhibits on behalf of Portland General Electric. Docket No.UE-88 Remand. February 15, 2005. Subject: The cost consequences of abandoning the regulatory compact in Oregon on prudent invested capital.

Before the Public Utilities Commission of Nevada, Testimony and Exhibits on behalf of Sierra Pacific Power Company. Docket No 05-1028. January 5, 2005. Subject: Prudence of gas purchase costs.

Before the Public Utility commission of Oregon, Direct Testimony on behalf of Portland General Electric. Docket No. UE-165. November 17, 2004. Subject: Power supply risk related to PGE's hydroelectric generation sources.

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Before the Illinois Commerce Commission, Testimony on behalf of Nicor Gas Company. Docket No. 04-0779. November 1, 2004. Subject: Cost of Capital.

Rebuttal Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 15, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Testimony before before the ICSID (International Center for the Settlement of Investment Disputes) on behalf of Azurix Corp., in the case of Azurix Corp v. Government of Argentina in Paris, France, October 11th, 2004. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the Circuit Court of Fairfax, Virginia, Testimony of Jeff D. Makholm on behalf of Upper Occoquan Sewage Authority in the case against Blake Construction Co., Inc., Poole and Kent, a Joint Venture. Case No. 206595. October 1, 2004. Subject: Valuation of capacity expansion project.

Expert Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 1, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Rebuttal Report before the London Courts of International Arbitration on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. September 17, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Expert Report before the London Courts of International Arbitration on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. August 6, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

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Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-12002. March 29, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

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Before the New Zealand Commerce Commission, Testimony on behalf of Orion New Zealand. November 5, 2003. Subject: Productivity measures used in resetting the price path thresholds for electricity distributors in New Zealand.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. September 2, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of FairPoint New England Telephone Companies. July 11, 2003. Subject: Cost of capital.

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Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-1014. May 5, 2003. Subject: Prudence of gas procurement and hedging program.

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RECENT TESTIMONY (SINCE 1994) (CONT.)

Before Federal Communications Commission, Testimony on behalf of Iowa Telecommunications Services, Inc. Case No. March 25, 2003. Subject: Cost of capital.

Before Federal Energy Regulatory Commission, Testimony on behalf of PPL Wallingford Energy LLC. Case No: ER03-421-000. January 9, 2003. Subject: Cost of equity.

Before the State of New Hampshire Public Utilities Commission, Rebuttal Testimony on behalf of Kearsarge Telephone Company. Case No. DT 01-221. December 20, 2002. Subject: Rebuttal on cost of equity.

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Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, September 18, 2001. Subject: Economic pricing for unbundled retail distribution services.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Before the State of New York Public Service Commission, Prepared Rebuttal Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. ,September 12, 2001. Subject: Electric price protection plan

Before the State of Maine Public Utilities Commission, Joint Rebuttal Testimony of Jeff D. Makholm and Charles J. Zarkadas on behalf of Community Service Telephone Company. September 6, 2001. Subject: Cost of equity capital.

Before the Public Service Commission of the State of Missouri, Rebuttal Testimony on behalf of Gateway Pipeline Company. Case GM-2001-595. August 20, 2001. Subject: Acquisition of Capital Stock of Utilicorp Pipeline Systems, and connection.

Before the State of New York Public Service Commission, Prepared Direct Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. August 3, 2001. Subject: Electric price protection plan.

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Before the Illinois Commerce Commission, Direct Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, June 1, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Federal Energy Regulatory Commission, Affidavit of Jeff D. Makholm, Ph.D. on behalf of Florida Power & Light Co. May 31, 2001. Subject: Pricing of transmission services.

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RECENT TESTIMONY (SINCE 1994) (CONT.)

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Before the Federal Energy Regulatory Commission, "Assessment of PJM Owner's Transmission Enhancement Package," prepared in support of the PJM (Pennsylvania, New Jersey, Maryland) electricity transmission owners as part of their Order No. 2000 compliance filing. Docket No. RT01-2, October 11, 2000. Subject: Analysis of incentive package for transmission efficiency.

Before the Appeal Panel under Section 38(2) of the Office of the Regulator-General Act 1994, Victoria, Australia. In the matter of an appeal pursuant to s.37 of the Act brought by United Energy Ltd., Testimony on behalf of the Office of the Regulator General, October 10, 2000. Subject: The distinctions between price cap and traditional cost-based regulatory practices.

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Before the State of Maine Public Utilities Commission, Surrebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, August 10, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the State of New Jersey Board of Public Utilities, Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564 , July 26, 2000. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, June 22, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 12, 2000. Subject: Investigation Concerning the Unbundling of delivery Services Under Section 16-108 of the Public Utilities Act.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 5, 2000. Subject: Investigation Concerning the Unbundling of delivery Services Under Section 16-108 of the Public Utilities Act.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase II, October 21, 1999. Subject: Billing credits for unbundled services.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0115, October 15, 1999. Subject: Recouping nuclear decommissioning expenses for electric power plants.

Before the State of Maine Public Utilities Commission, Report on behalf of Central Maine Power Company, Case No. 97-580 (Phase II), October 12, 1999. Subject: Cost of service for unbundled electricity transmission and distribution.

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Before the High Court of New Zealand, The Commerce Commission versus Caltex New Zealand Limited, Mobil Oil New Zealand and Shell New Zealand Limited. Reply Brief of Evidence, August 23, 1999. Subject: Price fixing in petroleum marketing.

Before the State of New Hampshire Public Utilities Commission, Direct Testimony on behalf of Chichester Telephone Company, Kearsarge Telephone Company, and Meriden Telephone Company, July 19, 1999. Subject: Determination of a fair cost of capital.

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Before the State of Connecticut, Department of Public Utility Control, Prefiled Testimony on behalf of The Southern Connecticut Gas Company, Case No. 99-04-18, June 18, 1999. Subject: Recoverability of pipeline expansion costs.

Before the Illinois Commerce Commission, Surrebuttal Testimony on Behalf of Commonwealth Edison Company, Case No. 99-0117, May 17, 1999. Subject: Whether marginal cost pricing principles can provide the basis for an efficient tariff design for the company's delivery service tariffs.

Before the Illinois Commerce Commission, Rebuttal Testimony on Behalf of Commonwealth Edison Company, Case No. 99-0117, May 10, 1999. Subject: Whether marginal cost pricing principles can provide the basis for an efficient tariff design for the company's delivery service tariffs.

Supplementary Submission before IPART in New South Wales, Australia on behalf of Incitec Limited, April 27, 1999. Subject: Discussion of reload practices, customer contributions, operating expenses and recalculates charges for a user of the distribution network in AGLGN's Proposed Access Arrangements.

Supplementary Submission before IPART in New South Wales, Australia on behalf of BHP, April 15, 1999. Subject: calculation of AGLGN's costs and tariffs in New South Wales.

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RECENT TESTIMONY (SINCE 1994) (CONT.)

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Before the Federal Energy Regulatory Commission, Reply Testimony on behalf of CITGO Petroleum Corporation, Case No. OR-99-1, March 19, 1999. Subject: To review and comment on Explorer Pipeline's application to the Federal Energy Regulatory Commission for market-based oil pipeline rates.

Before the State of Illinois, Illinois Commerce Commission. Reply Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, February 17, 1999. Subject: Unbundling services provided by electric distribution companies.

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Before the Federal Energy Regulatory Commission, Prepared Comments submitted on behalf of the Edison Electric Institute on the Commission's "ISOs and Transmission Pricing" Panel, Docket No. PL98-5-000. (April 16, 1998).

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Before the Pennsylvania Public Utility Commission, Prepared Direct Testimony on behalf of Duquesne Light Company, Docket No. R-00974104, July 12, 1997. Subject: Cost of capital and treatment of stranded electric utility costs as part of Pennsylvania's overall electricity restructuring plan.

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Before the State of Rhode Island and Providence Plantations Public Utilities Commission, Prepared Direct Testimony on behalf of Valley Resources, Inc., Case No. 2276, January 19, 1995. Subject: Cost of capital.

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Before the Federal Energy Regulatory Commission, Prepared Rebuttal Testimony on behalf of the New England Customer Group of 15 Natural Gas Distribution Companies, Docket No. RP91-203-000 (Tennessee Gas Pipeline Company), May 27, 1994. Subject: Gas pipeline rate design.

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"Tarificación de los Servicios Que Prestan las Terminales de Gas LP" (January 9, 1998). The final report given to PEMEX Gas y Petroquímica Básica (México) for the determination of rates for LPG terminals.
"NERA-Pérez Companc Distribution Tariff Model" (January 5, 1998). This report explains the methodology behind NERA's calculations of distribution tariffs for Pérez Companc in Monterrey.

"Monterrey Natural Gas Market Assessment," (January 5, 1998). A series of reports were written to present the results of the market study of the demand for natural gas in the geographic zone of Monterrey to a company interested in bidding for the natural gas distributorship.

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Handbook for Calculating Open-Access Gas Transportation and Distribution Tariffs

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"Open Access in Gas Transmission,"—Speech given at the New England Chapter of the International Association for Energy Economics, Boston, Massachusetts, December 13, 1995.

"Light-Handed Regulation for Interstate Gas Pipelines,"—Speech given at the Twenty-Seventh Annual Institute of Public Utilities Conference, Williamsburg, Virginia, December 12, 1995.

RECENT SPEECHES (CONT.)

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"Promoting Markets for Transmission: Economic Engineering or Genuine Competition?"—Speech given at The Forty-Ninth Annual Meeting of the Federal Energy Bar Association, Inc., May 17, 1995.

"End-Use Competition Between Gas and Electricity: Problems of Considering Gas and Electric Regulatory Reform Separately,"—Panelist on panel at ORLANDO '95, The Fourth Annual DOE-NARUC Natural Gas Conference, Orlando, Florida, February 14, 1995.

"Incremental Pricing: Not a Quantum Leap,"—Speech given at the 1995 Natural Gas Ratemaking Strategies Conference, Houston, Texas, February 3, 1995.
"The Feasibility of Competition in the Interstate Pipeline Market,"—Speech given at the Institute of Public Utilities Twenty-Sixth Annual Conference, Williamsburg, Virginia, December 13, 1994.

"A Mirror on the Evolution of the Gas Industry: The Views from Within the Business and from Abroad,"—Speech given at the 1994 LDC Meeting-ANR Pipeline Company, October 4, 1994.

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"Sources of and Prospects for Privatization in Developed and Underdeveloped Economies," —Speech given at the Spring Conference of the International Political Economy Concentration and the National Center for International Studies at Columbia University, New York, March 30, 1994.

"Experiencias en el Desarrollo del Mercado de Gas Natural (Experiences in gas market development)," —Speech given at the conference "Perspectivas y Desarrollo de Mercado de Gas Natural," Centro de Extensión de la Pontificia Universidad Católica de Chile, November 16, 1993.

"The Role of Rate of Return Analysis in a More Progressive Regulatory Environment,"—Speech given at the Twenty-Fifth Financial Forum held by the National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 27, 1993.

"Privatization of Energy and Natural Resources,"—Speech given at the International Privatization Conference "Practical Issues and Solutions in the New World Order," New York, New York, November 20, 1992.

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE

ELECTRIC UTILITY

AEP Energy Services, Inc
Alberta Power Limited
American Electric Power Company
Atlantic Electric Company
Boston Edison Company
Central Hudson Gas and Electric
Central Maine Power Company
Central Power & Light Company
Commonwealth Edison Company (Unicom/Exelon)
Commonwealth Energy System
Consolidated Edison Company of New York, Inc
Conowingo Power Company
Duquesne Light Company
Edison Electric Institute
Entergy Gulf States, Inc
Florida Power and Light Company
Green Mountain Power Company
Long Island Lighting Company
Massachusetts Municipal Wholesale Electric Company
Massachusetts Electric Company
Nantahala Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power
Ohio Power Company
Orange & Rockland Utilities
Pennsylvania Power and Light Company
Pennsylvania Power Company
Philadelphia Electric Company
PJM electricity transmission owners
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Electric and Gas Company
Portland General Electric Company
Reliant Energy HL&P
Rochester Gas and Electric Corp.
Sierra Pacific Power Corporation
Southwest Electric Power Company
Southwestern Public Service Company
Tampa Electric Company
Texas-New Mexico Power Company
TXU Electric Company
United Illuminating Company
UtiliCorp Networks Canada
Virginia Electric and Power Company
West Penn Power Company
West Texas Utilities Company
Western Massachusetts Electric Co.

GAS UTILITY

ARKLA, Inc.
Atlanta Gas Light Company
Bay State Gas Company
Berkshire Gas Company
Blackstone Gas Company
Boston Gas Company
Bristol & Warren Gas Company
British Gas plc
Brooklyn Union Gas Company
Canadian Western Natural Gas
Chattanooga Gas Company
Colonial Gas Company
Commonwealth Gas Company
Connecticut Natural Gas Corp.
Consolidated Gas Supply Corp.
Elizabethtown Gas Company
Empire State Pipeline Company
ENAGAS (Spain)
EnergyNorth, Inc.
Essex County Gas Company
Fall River Gas Company
Fitchburg Gas & Electric Light Company
Gas and Fuel Corporation of Victoria
Gateway Pipeline Company
Granite State Gas Transmission, Inc.
Great Falls Gas Company
Holyoke, Mass. Gas & Electric Dept.
ICG Utilities (Ontario) Ltd.
KN Energy, Inc.
Middleborough Municipal Gas & Electric
National Fuel Gas Distribution Corp.
Natural Gas Corporation of New Zealand
Natural Gas Pipeline of America
Norwich Department of Public Utilities
Pacific Gas Transmission
Pemex Gas y Petroquímica Básica
Pennsylvania Gas and Water Company
Peoples Gas Light and Coke Company
Providence Gas Company
Southern Connecticut Gas Company
Southwest Gas Corporation
Transwestern Pipeline Company
Valley Gas Company
Washington Gas Light Company
Westfield Gas & Electric Light Dept.
Wisconsin Gas Company
Yankee Gas Services Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (CONT.)

TELEPHONE UTILITY

Centel Corporation
Chichester Telephone Company
Community Service Telephone Company
Continental Telephone Company of Illinois
General Telephone of Pennsylvania
General Telephone Company of Ohio
Kearsarge Telephone Company
Meriden Telephone Company
Pacific Bell Telephone Company
Tipton Telephone Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (CONT.)

REGULATORY AND GOVERNMENT

Delaware Public Service Commission
re: Delmarva Power & Light Company

District of Columbia Public Service Commission
re: Potomac Electric Power Company
Washington Gas Light Company

Massachusetts Municipal Wholesale Electric Company

The Government of Chile
Gas industry regulations

The Government of Argentina
Plan for privatized rail freight industry regulation

The Government of Tanzania
Natural gas development and regulation plan for Songo Songo Island gas reserves.
Financing the development of gas reserves on Songo Songo Island with emphasis on payment guarantee mechanisms for foreign exchange.

The World Bank
re: Natural gas tariffs for Polskie Gornictwo Naftowe i Gazownictwo (The Polish Oil and Gas Company)

re: Natural gas transport and distribution tariffs for Gas del Estado (The Argentine State-owned gas utility)

re: Natural gas development for the Moroccan Gas System.

re: Natural gas transport and distribution tariffs for the Bolivian Gas Industry.

re: Natural gas development plan for Sichuan province of China.

OTHER

Air New Zealand
BHP Petroleum Pty Ltd
Centel Corporation
General Electric Company
Intel Corporation
Jamaica Water Supply Company
Nucor Steel Corporation
Parsons Brinckerhoff Development Group

MEMBERSHIP IN PROFESSIONAL ORGANIZATIONS

The American Economic Association

Credit Rating Agency Quotations

While the presence of FACs have always been noteworthy in ratings agency reports for the electric utility sector, the greater volatility of the wholesale power markets has caused them generally to heighten their focus. This was especially true during and after the Western-US energy crisis. In terms of fuel adjustment clauses and utility credit quality, *S&P* states:

> Standard & Poor's is frequently asked what weight is given to FPPA. It is clear that continued gas price volatility and upward trends in historically stable coal prices underscore the importance of FPPAs....to the extent that an FPPA is transparent and well structured, regulators are likely to be less inclined to disallow a utility's fuel and purchased-power costs.[1]

Fitch Investor's Service (formerly *Duff & Phelps*) discusses the extreme adverse consequences of a state not enacting an FAC:

> California remains an extreme example of what can go wrong when FACs are eliminated, rates are frozen, and regulators are either unable or unwilling to extend support to local utilities.[2]

Three years after the Western-US energy crisis, *S&P* stated the following:

> It has been more than three years since the California energy crisis led to the rapid deterioration of credit quality for many Western electric utilities...The severe market distortions of the California crisis have faded, but FPPAs continue to play a significant role in the financial well-being of western electric utilities. Natural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development are daily reminders that **it is increasingly difficult for utilities to sustain their financial health solely through the use of hedging policies and regular general rate case filings** [emphasis added][3]

Fitch also discusses the effect of an FAC on an IOUs bond rating:

> In today's environment, the safest bonds in the utility industry may be those of vertically integrated utilities operating under commission-approved mechanisms to recoup prudently incurred power costs. Such companies typically operate in

1 *Standard & Poor's* "Fuel and Power Adjusters Underpin Post-Crisis Quality of Western Utilities," October 14, 2004.

2 *Fitch*, "Natural Gas Price Sensitivity of the U.S. Utility Sector," July 1, 2004, p. 7.

3 *Standard & Poor's* "Fuel and Power Adjusters Underpin Post-Crisis Quality of Western Utilities," October 14, 2004.

> supportive regulatory environments which continue to feel the need for healthy reserve margins of generation.[4]

In terms of handling fuel volatility, *Moody's* states that:

> Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages.... Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.[5]

In terms of natural gas price sensitivity of the U.S. Utility Sector, *Fitch* states that:

> The high price of natural gas and the increased price volatility witnessed during the past three years have presented challenges of varying degrees to issuers in U.S. electric and gas coverage. The ability of these companies to manage commodity price exposure varies considerably among firms within the sector and is an important rating factor.... However, integrated utilities with the obligation to serve and no adequate fuel cost recovery mechanism, as well as electric distributors operating under frozen rate tariffs that are required to defer power purchases, are generally more exposed to volatile commodity prices.[6]

In 1998, *S&P* noted that "[a]utomatic pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."[7]

With respect to integrated utility companies, *Fitch* states,

> Although a majority of integrated utilities remain substantially protected from fluctuating commodity price levels due to the existence of fuel/purchased power adjustment clauses (FACs), a handful of companies possesses regulatory mechanisms that offer only partial protection while others lack such a clause altogether.... Unless a protective adjustment mechanism is in place, utilities purchasing power from the spot market to meet load requirements will be particularly exposed to high costs during periods of high demand, when gas is likely to be on the margin in all U.S. regions.[8]

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[4] *Fitch*, "Procuring Power in California: A Potential Stranded Cost," September 7, 2000, p. 4.

[5] *Moody's Investors Service*, "Credit Implications of Power Supply Risk," July 2000, p. 3.

[6] *Fitch*, "Natural gas Price Sensitivity of the U.S. Utility Sector," July 1, 2004, p. 1.

[7] *Standard & Poor's*, "Rating Methodology For Global Power Utilities," *Standard & Poor's Infrastructure Finance*, September 1998, p. 66.

[8] F*itch*, "Natural gas Price Sensitivity of the U.S. Utility Sector," July 1, 2004, p. 4.

Moody's mirrors *Fitch's* sentiments by stating:

> Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages.... Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.[9]

With regard to Provider of Last Resort service in restructured states, *Moody's* states that:

> In general, utilities have little incentive to accept the financial risk PLR service creates without being compensated by regulators with some form of pass-through. Each state will determine its own plan, and Moody's believes that elements of a purchased power adjustment clause will be retained for PLR service.[10]

These are typical passages from ratings agency reports in the era of competitive power markets. The ability of electric utility companies to charge compensatory rates in light of changing wholesale power costs is of key importance in assessing the risk to which investors expose their capital.

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[9] *Moody's Investors Service*, "Credit Implications of Power Supply Risk," July 2000, p. 3.

[10] *Id.*, p. 3.

HELCO ST-24
DOCKET NO. 05-0315

SUPPLEMENTAL TESTIMONY OF
EUGENE T. MEEHAN

On Behalf of
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Fuel Hedging Overview

SECTION 1: INTRODUCTION

Q. Please state your name and business address.

A. My name is Eugene T. Meehan. I am Senior Vice President at National Economic Research Associates ("NERA"). My business address is 1255 23 St. NW, Washington, DC 20037.

Q. Please summarize your professional qualifications.

A. I have over twenty-five years of experience consulting with electric and gas utilities. That work has involved examination and advice on many issues related to power markets, power contract design, utility fuel and purchased power procurement and hedging, competitive bidding and contract evaluation. For the past ten years, I have been extensively involved in advising clients on restructuring-related issues, including risk analysis, risk management, power plant and power contract valuation, and post-transition regulatory issues. In the past few years, I also have advised several utilities with respect to the acquisition of power from third parties. These assignments have involved the review of power contract offers made by competitive power marketers and owners of generation assets. Additionally I have testified several times with respect to the prudence of utility planning and power procurement. HELCO-S-2400 contains a more detailed statement of my qualifications.

Q. Will you briefly describe the nature of NERA's business?

A. NERA is a firm of over 450 professional economists located in offices throughout the United States, Europe, Asia and Australia. NERA provides consulting advice in litigation and regulatory settings, as well as strategic and planning advice to clients in the energy, telecommunications, television and broadcasting, securities, transportation, health and banking industries.

Q. Please describe the scope of your testimony.

A. I was asked by Hawaii Electric Light Company ("HELCO") to address the possibility of fuel price hedging by HELCO in response to Act 162 ("the Act"), which was signed into law in Hawaii on June 2, 2006. My testimony provides a summary of the type of fuel price hedging that potentially could be performed by HELCO in the marketplace and an assessment of the potential impacts of fuel price hedging on HELCO, its customers and the regulatory ratemaking process that are undertaken before the Public Utilities Commission of the State of Hawaii ("Commission"). I also submitted testimony, HECO T-22, on behalf of HELCO's affiliate, Hawaiian Electric Company, Inc. ("HECO"), in Docket No. 2006-0386, on similar topics .

Q. Please provide a definition of hedging.

A. The Edison Electric Institute ("EEI") defines hedging as "the attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks."[1] Hedging can, in principle, allow a utility to offset and reduce risk as it procures fuel and purchased power on behalf of its customers.

Q. Can you describe HELCO's current oil procurement practices?

A. Yes. HELCO generates electricity primarily by burning oil. To ensure a reliable physical supply of oil, HELCO has a variety of oil supply contracts that provide for it to obtain fuel oil delivered to its plants that is physically suitable to burn. These contracts call for HELCO to pay a price each month based on contract formulas. The key factor affecting these formulas is the relevant oil index on a daily basis over the month. The oil index is the reported market price of

[1] EEI Glossary of Electric Industry Terms, April 2005.

transactions in a standard oil product at a particular location. For example, the contract for the industrial fuel oil burned by HELCO is tied to the daily index for L.A. Bunker C fuel oil. This is a sensible index as it is economic for HELCO's supplier to acquire such oil to meet HELCO's needs and as HELCO's supplier will want to sell at a market price.

Purchasing oil at a formula rate tied to oil products that are traded in the worldwide oil market means that HELCO's fuel costs will vary with world oil prices. It also means that HELCO's fuel supplier is not taking world oil price risk, and can offer HELCO a price free of a world oil price risk premium. Thus, HELCO can offer its customers a price for electricity that is free of any risk premium associated with bearing world oil price risk.

Q. How does this relate to Act 162?

A. Act 162 raises the question of whether HELCO should hedge by reference to "fuel hedging contracts" as a commercially available means to mitigate the risk of fuel price changes.[2] Hedging with respect to energy commodities can take two forms: (i) physical hedges, such as physical supply contracts and fuel inventories; and, (ii) financial hedges, such as fixed-price financially-settled futures contracts and financial options contracts. HELCO could, in theory, hedge fuel by buying financial products called oil price futures. Were HELCO to buy oil price futures, it would realize profits when oil prices rose and losses when oil prices dropped. This is a hedge, because the gain or loss is opposite in direction to what HELCO pays for oil under its contracts. For example, assume an oil price future for next July was available at $70 per barrel. HELCO will buy oil next July at the formula rate. If HELCO bought a future now at $70 and prices in July dropped to $50,

[2] Act 162, (g) (iii).

HELCO would lose $20 per barrel. However, it would only pay $50 in July. The loss would offset or hedge the actual purchase cost. If, on the other hand, the price rose to $100 in July, HELCO would actually pay $100 for oil at the time. However, if it had hedged by purchasing a $70 future, it would realize a $30 per barrel profit that would offset its actual purchase cost. That profit is a hedge. Hedges are accomplished using financial instruments called derivatives. They are called derivatives, because their value is derived from the market price of an underlying commodity. An oil future, for example, is settled against the price of oil and is an oil derivative. HELCO would buy derivatives and the value of these derivatives would rise when HELCO's actual contract purchase costs rose, and fall when HELCO's actual contract purchase costs fell. Thus, they would offset or hedge actual contract purchase costs.

Q. What factors may prevent hedging from achieving the goal of safe, adequate and reliable service at the lowest reasonable cost?

A. There are four factors to consider:

- *Downward price movements may be foregone.* Locking in a price for oil today or at some fixed point for delivery in the future does not provide for a lower price, just a known price. The price locked in may well be higher than the price in the future at which HELCO actually purchases oil. Hence, hedging does not provide for lower prices. It only increases predictability, which may not be perceived as beneficial by all customers.
- *Hedging involves costs.* These costs are incremental to the fuel acquisition costs when fuel is not hedged. Customers can expect to pay more if HELCO adopts fuel hedging. It is not at all clear that increased predictability is worth the extra costs.

- *Hedging is imperfect.* The example of a single barrel of oil selling for $50, $70 or $100 is a simplification of the actual situation facing HELCO. Perfect hedges can only be accomplished when the hedged product is identical to the acquired product and when the volume needed by the hedger is certain. HELCO could not buy derivatives that correspond exactly to the product that will be acquired. It would need to hedge using similar, but not identical, products. This poses what is called basis risk. Basis risk is the difference in price movement between the derivative used to hedge and the price movement in the product that will actually be bought. In HELCO's case, basis risk is substantial because the indexes in HELCO's oil contracts are not traded in the most liquid and transparent derivatives markets and because the closest substitutes are only traded in less liquid and less transparent derivative markets. When a regulated utility hedges, it is best done in transparent liquid markets. The products available in the transparent and liquid oil derivative markets, however, do not move in lock step with the indexes in HELCO's contracts. Further, HELCO pays for oil based on average daily prices in the indexes. If HELCO were to hedge, it would settle once a month and this itself would create a basis difference between the derivative used and HELCO's actual costs. This basis difference means that if HELCO were to attempt to hedge, it could only partially do so, and its hedges would not be fully effective. I have looked at several years of historic data and have found that this is not just an academic issue. HELCO would have a difficult time placing effective hedges.
- *Limited duration of financial hedges.* HELCO could hedge oil prices at most for a year out in the future. Hence, while there may be an enhanced degree

of price predictability, it would be for a limited time and would not protect customers against long term trends in oil prices.

Q. With these factors in mind, what do you conclude?

A. My conclusions with respect to fuel price hedging are as follows.

(1) Even if rate smoothing is a desired goal, there may be more effective means of meeting the goal. There is no compelling reason for HELCO to use fuel price hedging as the means to achieving the objective of increased rate stability.

(2) While HELCO could partially hedge against oil price risk for periods of just over a year into the future, there would be considerable costs to doing so. The liquidity of standard financial hedging products with a term of over a year is limited. Given this, price hedging should not be expected to address rate periods of more than one year at a time.

(3) Were HELCO to hedge, it would at best be able to partially hedge as there are considerable differences in price fluctuations between the hedges HELCO could readily purchase and the cost of the oil it burns. Further, the exact volume of oil needed is not knowable with certainty. Moreover, prices should signal costs. While some customers may desire rate stability and predictability, and be willing to pay, others may not be willing to pay for predictability. One way to deal with this issue would be to allow customers to "opt in" to rate stability programs, such as hedging initiatives that may be expected to raise average overall costs to customers.

(4) Were HELCO to hedge, it would encounter periods during which it experienced gains on its hedges and other periods during which it experienced losses. The gains in large part would be offset by increased fuel

purchase costs and the losses in large part would be offset by reduced fuel purchase costs. The ECAC framework would need to be revised so that the difference between the gains and increased fuel costs and the difference between the losses and reduced fuel costs were reflected in rates through the ECAC.

(5) Hedging of oil by HELCO would not be expected to reduce fuel and purchased power costs and, in fact, would be expected to increase the level of such costs.

(6) It would not be reasonable for HELCO to take the position of a principal and speculate in the oil market with shareholders assuming the risk of oil derivative gains and losses.[3]

Q. Please explain the basis for your first conclusion that if increased rate stability is the objective, there is no compelling reason to achieve this by fuel hedging.

A. The basis for this conclusion is rooted in the fact that hedging carries a limited scope of benefits, and also implies costs and risks for customers.

The scope of benefits from hedging is limited by the realities of the oil hedging marketplace and HELCO's physical location. First, the duration of any benefit is limited: the markets do not offer reasonable hedging solutions that would permit HELCO to manage oil price-driven rate fluctuations for more than one year at a time. Second, there is no *ex ante* expected price benefit. Even if hedging can stabilize purchased oil prices to some degree, the stabilized price may be higher or lower than the price that would have been achieved absent the hedging program. On average, costs can be expected to be higher with a hedging program. Third,

[3] Derivatives are a term used to describe financial instruments whose value is derived from the price of an underlying commodity. Hence, an oil price swap is a derivative as its value is based on the price of oil, the underlying commodity.

the amount of fuel cost stability that can be achieved is uncertain due to basis risks, quantity risks and other risks. HELCO cannot enter into readily-traded fuel hedging contracts that eliminate all exposure to oil price fluctuations; such contracts do not exist in the marketplace. The risks inherent in available fuel hedging contracts create uncertainties as to how effective hedging products would be in stabilizing prices for customers. The cost of bearing these risks is potentially high.

Further, HELCO may be able to achieve increased short-term rate stability more effectively through the ratemaking process. My colleague, Dr. Jeff Makholm, discusses these alternatives in HELCO ST-23.

Q. Please explain the basis for your second conclusion, that price hedging could not be performed for periods of greater than one year and that hedging could not eliminate all fuel price risk for HELCO's customers.

A. My conclusion that it is not reasonable for HELCO to enter into hedges of greater than one year is based primarily on my analysis of the oil hedging market. I examined the types of price-risk management contracts that are available through the over-the-counter ("OTC") market and exchange markets. I found that the contracts that are most actively traded are the contracts for very near term deliveries, *i.e.*, delivery within the next three to six months. In addition, I found some trading of contracts for deliveries covering six to eighteen months in the future. For deliveries in periods beyond eighteen months in the future, trading is very thin or non-existent.

The most liquid exchange-traded contracts that would be available to hedge the fuel needs of HELCO are the New York Mercantile Exchange ("NYMEX") heating oil futures contract based on pricing at New York Harbor and the

NYMEX West-Texas Intermediate crude oil futures priced at Cushing, Oklahoma. To illustrate how trading drops off for longer-dated delivery periods for these contracts, I have provided HELCO-S-2401 as an example of the daily trading volume, open interest and forward prices for each futures contract.

HELCO-S-2401 illustrates how liquidity is concentrated in the near-term delivery months. Hedging with contracts that are thinly traded poses risks and tends to be more expensive. Given the trading activity for these futures markets, it would not be reasonable to expect HELCO to hedge beyond 12 months into the future. It is important to recognize that there are higher liquidity risks associated with the longer-dated contracts, and there would be liquidity risks and illiquidity premiums even within the twelve-month time horizon.[4]

Q. Please explain the basis for your third conclusion, that were HELCO to hedge it would at best be able to partially hedge.

A. Based on my review of HELCO's existing physical fuel contracts and my review of available price hedging products in the marketplace, HELCO would not be able to eliminate all of the risk of oil price fluctuations. The fuel contracts contain complex pricing provisions that are based in part on published fuel assessments, but also contain adjustments for product quality and in some cases freight costs. This means that even if HELCO were able to hedge the published assessment, the final cost of delivered oil would remain subject to residual price risks that could not be hedged.

Further, my review of the over-the-counter oil derivatives markets turned up no visible contracts for the specific fuels that are referenced in HELCO's fuel supply contracts. As I have explained above, this means that HELCO would have to bear

[4] From a regulatory standpoint, great care would be necessary to judge hedging costs based on what would have been known by a reasonable utility at the time that the decisions were made.

the basis risks or pay a premium to shift those risks to a third-party via a customized swap, which may be expected to increase average costs for customers. Moreover, the fuel hedging contracts that are available in the marketplace are for fixed quantities. HELCO's customers would therefore bear market risk exposure for incremental or decremental quantities relative to the fixed quantity that is hedged by HELCO.

All of these factors imply that even with a short-term price hedging program, there would still be fluctuations – potentially large fluctuations – in HELCO's cost of fuel.

Q. Please explain the basis for your fourth conclusion, that price hedging would create gains and losses and that these gains and losses would need to be flowed through the ECAC mechanism.

A. Gains and losses are a natural part of hedging. Through its price hedging activities, HELCO would effectively be using forward contracts to lock in a price for oil for delivery periods in the future. If prices for those delivery periods rise subsequent to HELCO's having locked in its price, HELCO will experience a gain on its hedge. If prices fall subsequent to placing its hedge, HELCO will experience a loss. The mechanics of financial settlement of the hedges are such that any differential between the forward price locked in and the price at maturity would be multiplied by the fixed quantity that HELCO had hedged to arrive at a settlement cost for the contract. The hedging contracts will create gains and losses, but as noted, those gains and losses will be partially offset by changes in the cost of delivered oil.

The net result is that HELCO would continue to experience variable net fuel and hedge costs even with a hedging program. In HELCO ST-23, Dr. Jeff Makholm elaborates on the reasons why it is important to flow through the net fuel costs (i.e., fuel costs adjusted for hedge gains and losses) in an ECAC.

The reasons cited by Dr. Makholm for flowing through the cost of purchased oil through the ECAC are also applicable to hedging costs. Further, if hedging is pursued, it will be important for HELCO and the Commission to agree on the objective of hedging, an acceptable hedging program, including the specification of approved contract types and contract duration, an approved timescale for hedge execution, as well as the revisions to the ECAC cost recovery framework.

Q. Please explain the basis for your fifth conclusion, that price hedging by HELCO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the level of such costs.

A. Utilities are not in the business of predicting world oil prices and cannot be expected to consistently buy low. If fuel hedging contracts are entered into by HELCO, there will be no way to know on an *ex ante* basis whether market prices will move up and those hedges will lower rates for customers or whether market prices will move down and those hedges will raise rates for customers. There are certain explicit costs to hedging, and if pursued, HELCO would face new risks that it does not currently face. I have elaborated the costs and risks of hedging in HELCO-S-2402, which I will describe in more detail later in my testimony. These risks and costs lead to fuel costs from hedging that can be expected on average to be higher. The trade-off is an expected increase in rate stability at the cost of higher expected costs.

The notion that hedging is costly and can be expected to raise rates is cited by the National Regulatory Research Institute ("NRRI"):

> Hedging, in its purest form, does not provide a means to

> reduce the expected price of gas for a utility. Rather, from the consumers' perspective its primary function is to stabilize prices. Generally, risk-adverse consumers should be expected to pay extra for shouldering less risk, such as exposure to volatile prices.[5]

Q. Please explain the basis for your sixth conclusion that HELCO should not engage in hedging as a principal and place shareholder funds at risk.

A. The motivation for hedging would be to provide rate stability for customers. HELCO would thus be entering into hedges on behalf of customers, not on its own behalf. It is logical that customers bear the risks and rewards of hedging. Under the regulatory compact, shareholders bear certain risks and reap certain rewards. However, gains or losses on hedges that were entered into on behalf of customers under the direction of the Commission should not be shareholder responsibility. My colleague, Dr. Makholm, explains in HELCO ST-23 why having the utility share in the risk of input costs when the utility is purchasing in world markets and is a price-taker is contrary to sound regulatory practice and would violate the regulatory compact.

Q. Please describe how your testimony is structured.

A. In Section 2, I provide an overview of hedging and the reasons why firms choose to hedge. In Section 3, I describe HELCO's current oil positions and existing hedges and explain the risk mitigation function that those hedges serve. Section 4 addresses several alternatives for hedging price in the marketplace, specifically explaining forward contracts, call options and collars. In Section 5, I explain the realities of the marketplace for oil derivatives and the costs and risks of entering

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[5] Ken Costello, "Regulatory Questions on Hedging: the Case of Natural Gas," National Regulatory Research Institute, February 2002, p. 17. Reprinted in *Electricity Journal*, May 2002, p. 51.

into fuel hedging contracts.

SECTION 2: BACKGROUND AND OVERVIEW OF HEDGING ON BEHALF OF UTILITY CUSTOMERS

Q. What types of hedging does your testimony address?

A. I assess price hedging for liquid fuels used by HELCO to generate electricity. As I explain below, HELCO already engages in physical hedging through its supply contracts.

Q. Based on your experience and knowledge of hedging and its implementation, please address the duration of hedging contracts. Are hedging contracts by nature short-term or long-term?

A. In regulatory parlance and in many industries, the term "hedging" most often refers to short-term activities. By short-term, I mean a year in duration or less. This is because forward markets offer liquid price hedging contracts covering delivery periods that often extend only for one or two years forward. For the oil derivatives markets, price hedging contracts are only reasonably available for periods of up to twelve months. This means that hedging contracts, if pursued by HELCO, could only mitigate the impacts of oil price changes on costs and rates for a defined period such as one quarter or potentially one year. Fuel hedging contracts could not be expected to cover durations longer than this.

Long-term hedging – i.e., hedging for more than one year in the future – cannot reasonably be achieved through commercially available fuel hedging contracts. Long-term hedging for HELCO would require investment in non-oil based generation capacity, either through rate-based generation or through long-term contracts with non-utility generators.

Q. Does your testimony address short-term or long-term hedging?

A. My testimony primarily addresses short-term hedging, as this is my understanding of what should be examined as a result of the language in the Act that refers to commercially available fuel hedging contracts. The only fuel hedging contracts that are available in the marketplace are by nature short-term. Long term hedging could not be accomplished with commercially available fuel hedging contracts, and is more appropriately considered resource diversification.

Q. Is hedging necessarily beneficial?

A. No. It depends on the objective of the entity engaged in the hedging. Hedging is most often done to lock in a range of outcomes and not to maximize expected value. In fact, hedging reduces the expected value of profitability and raises the expected value of power costs. Hedging can be beneficial to a firm that seeks to reduce the range of potential outcomes, but hedging creates costs and risks.

Q. Under what specific circumstances might hedging be appropriate?

A. There are certain situations where firms face business or financial risks that make hedging particularly important. For example, if prices for the firm's product will remain relatively fixed as a significant input cost varies, then hedging that input cost may be necessary to protect cash flows and maintain financial stability. This will be the case when the firm is more reliant on a specific commodity than the industry in general and changes in that commodity's price do not have a proportional impact on market prices. This could also be the case when industry competitive pressures are so severe that product prices cannot rapidly adjust to meet changes in input costs.

Q. How does hedging differ from speculation?

A. Speculation is defined as taking a position with the intent to profit from a change in the price of the underlying commodity. Hedging differs from speculation in that hedging is intended to insulate profits from the effect of changes in the underlying commodity. Hedging is the polar opposite of speculation. Some activities deemed to be hedging by unregulated firms are actually speculation. This is the case when the firm seeks to profit from a change in the price of the underlying commodity as opposed to holding itself neutral to such a change.

Q. Why would a regulated utility engage in hedging?

A. The motivation for regulated utilities to hedge is different from the motivation of firms in competitive industries. Regulated utilities with highly variable fuel costs generally have fuel adjustment clauses in place that provide for timely and adequate recovery of costs.

Hedging by regulated utilities is oriented toward managing customer rates; its objective is to insulate customers from the price fluctuations in an underlying commodity. For example, some gas and power distribution utilities hedge the commodities they sell in order to provide a fixed- or near-fixed price to customers. It only makes sense to hedge if the intent is to sell at fixed or near fixed rates.

Q. What do you mean by the term "near fixed rates"?

A. In my experience it is very unusual for electric utilities to offer rates that do not fluctuate based on changes in fuel and purchased power markets. This can mean rates that fluctuate monthly, which give customers an economically-desirable price signal to reduce usage when power costs go up. It can also, however, mean rates that are near fixed, in that they are set for a period of time and differences are reconciled on a semi-annual or annual basis. In these circumstances, a utility may attempt to minimize differences by hedging with fixed price purchased power contracts or fuel hedges. I use the term near fixed rates as even in cases where a utility hedges, the rates are not completely fixed. Utilities are not well positioned to offer fixed rates, and even in instances where they may engage in some hedging, the rates are at most near fixed as opposed to fixed because complete (i.e., perfect) hedging is unachievable.

Q. In your experience, when regulated firms decide to engage in hedging programs, what is the degree of regulatory oversight of these programs?

A. My experience has been that hedging programs are designed and implemented by utilities in collaboration with the commissions that regulate them. The utilities agree upon an objective with the regulator and then they clearly establish a program for achieving that objective. The need for a regulated entity to hedge is created by a specific and customer focused objective, not by the economics of the regulated business model. Therefore, it must involve considerable regulatory oversight and guidance.

Q. Do regulated utilities hedge in order to obtain the best or lowest possible price for fuel?

A. No. That would not be hedging, it would be speculating. Any fuel hedging program with the objective of "timing the market" and "buying low," is not a hedging program. Utilities have no specialized expertise in identifying trends in world oil markets and cannot be expected to predict market high and low points. That job is left to professional traders and speculators. A utility should not be asked to speculate on behalf of its customers. Moreover, a utility should not bear any financial risk or reward related to the timing of hedge execution. Utilities hedge to lock in a current market price and reduce fluctuations and not to minimize fuel acquisition costs.

Q. How should HELCO and the Commission go about exploring hedging?

A. I recommend that HELCO explore hedging while recognizing the following:

1. There is no business reason for HELCO to hedge and the benefits to customers are unclear;
2. Fuel (oil) hedging by HELCO will be expected to result in increased customer costs and as such should only be seriously considered if there is a countervailing benefit;
3. Fuel hedging by HELCO may be able to reduce oil price-induced fluctuations in customer rates, but would not eliminate such fluctuations. While rate stability may be a countervailing benefit to the costs of hedging, hedging will provide, at best, *more* and not *absolute* rate stability;
4. If fuel hedging were to be implemented, fuel hedging objectives would need to be developed in close consultation with regulators and customers and approved a priori as hedging by HELCO would be on behalf of customers and not for HELCO's shareholders account; and,
5. If HELCO were to implement fuel hedging it should not speculate by attempting to time the market to minimize oil purchase costs.

Further, I would recommend that HELCO carefully consider limitations on its ability to hedge that are a function of marketplace realities and the implications of hedging on its financial position. I will describe these factors in later sections of my testimony.

SECTION 3: BACKGROUND ON HELCO'S CURRENT OIL POSITIONS AND EXISTING HEDGES

Q. Please describe HELCO's current oil positions and its existing hedge contracts.

A. In order to meet the electricity demands of its customers, HELCO operates oil-fired power plants. HELCO purchases the oil for these plants. HELCO's position in oil is therefore a short physical position. HELCO hedges its short physical position by entering into an offsetting long position in delivered oil. This long position is achieved through the Company's existing fuel supply contracts. These fuel supply contracts tie the price paid by HELCO for oil to a base component. The base component is the month-to-date average of a third-party assessment calculated on the 20th of the month before delivery. For example, HELCO's industrial fuel oil deliveries for January 2007 will be based on the average of the Platts Los Angeles Bunker C assessments from November 21st to December 20th 2006. The actual contract price includes taxes and a standard premium (based on quantity). Depending on the contract, the price may include a locational premium and adjustments for heat content, quality differentials and freight. In addition, the contracts provide for quantities and delivery of fuel that are more than sufficient to cover HELCO's needs. Hence, HELCO and HELCO's customers are hedged with respect to availability and delivery of the physical commodities. HELCO's fuel costs are variable as the price it pays will vary with the daily assessments in HELCO's fuel contracts.

With respect to price, despite the fact that the price varies with assessment values, HELCO is hedged from the perspective of the utility. HELCO's physical fuel supply contracts are struck at floating assessments. Similarly, its electricity rates float in accordance with the prices of oil that HELCO pays. As my colleague Dr. Jeff Makholm explains, this is a logical regulatory framework, since HELCO has no control over world oil prices. The matching of variable fuel operating expenses with variable electricity revenues helps to assure the financial integrity of the utility, while providing the economically-correct price signal to customers.

Q. If HELCO is hedged with respect to price, what is the relevance of the fuel hedging contracts cited in the Act?

A. The fuel hedging contracts referred to by the Act, if reasonably available, would only be entered into by HELCO to meet the objective of mitigating oil price fluctuations for customers. Customers are exposed to fluctuations in world oil prices, while hedged against availability and physical delivery risks and costs. If HELCO were to hedge price risk, it would reduce this price exposure. Of course, there would be a cost to reducing the exposure that may not be justified by the benefit.

SECTION 4: HEDGING ALTERNATIVES

Q. What strategies are available to buyers of commodities wishing to reduce exposure to short-term price fluctuations?

A. Buyers of commodities can use a number of different hedging strategies to manage short-term price risk. There are three strategies that are commonly used by buyers of commodities, which I explain in turn below:

1. Forward or futures contracts
2. Call option contracts
3. Collars (which are portfolios containing call option contracts and put option contracts)[6]

I will address each in turn.

Q. What is a forward contract?

A. A forward contract is an agreement between two parties to buy or sell an asset or commodity at a pre-agreed future point in time. A standardized forward contract that is traded on an exchange is called a futures contract.

Q. How are forward contracts used to hedge price risk?

A. Forward contracts are in most cases struck at fixed prices. A fixed-price forward

[6] A put option gives the owner the right, but not the obligation, to sell a commodity at specified price. Thus, a seller can use a put to determine a minimum price he will obtain on his sale.

contract locks in the price of the underlying commodity for both the buyer and seller. HELCO-S-2403 illustrates the effect of a forward contract purchase for a buyer who, like HELCO, would otherwise be purchasing the commodity on the open market at prevailing spot prices.

Using HELCO-S-2403 as an example, suppose HELCO fully hedges its fuel need with futures contracts at $40/bbl. No matter what happens to the price of oil from this point on, HELCO will pay $40/bbl for oil. However, even though the initial hedge may have been perfectly rational ex ante, subsequent decreases in the price of oil will increase costs relative to a no-hedging strategy and increases in the price of oil will decrease costs relative to a no-hedging strategy. This exhibit is illustrative of the impacts that purchasing forward can have on the price paid. However, this exhibit does not consider basis risks.

Q. What are basis risks?

A. Basis risks are the price risks that a buyer would be exposed to if the buyer cannot find a forward contract for the specific commodity it needs at the delivery location it needs. If the marketplace does not offer forward contracts that exactly match the commodity and the location where the buyer takes delivery, the buyer may purchase derivatives for a different commodity whose price is highly correlated with the product the buyer wishes to hedge. In addition, the buyer could purchase the same commodity it needs but at a delivery location other than the one where it takes delivery. In these cases, the buyer faces the risk associated with the difference in prices between the two commodities or the two locations. These price differences are termed basis risk.

Even firms engaged in sophisticated hedging programs, such as Southwest Airlines, have run into problems with respect to basis risk. While I am not an accountant, it is my understanding that Statement of Financial Accounting Standards No. 133 (FASB 133) has strict provisions regarding basis risk, requiring that ineffective portions of hedges do not qualify for special hedge accounting treatment. Southwest Airlines' hedging program aims to hedge the price of jet fuel, an underlying commodity that is not traded on an organized futures exchange. Southwest Airlines explains that "ineffective" hedges are inherent to "hedging jet fuel with derivative positions based in other crude oil related commodities" and goes on to explain that ineffectiveness "may result, and has resulted, in increased volatility in the Company's results."[7] Thus, it is clear that basis risk is a significant issue, and may, in fact, preempt HELCO from pursuing a financial hedging program that involves "ineffective" hedges. Customers may not be well served by hedges that involve basis risk.

As I explain further below, forward contracts are not readily available for the oil products and delivery locations that HELCO needs, which means that if HELCO decides to hedge, it will be exposed to considerable basis risk.

Q. What is a fixed-for-floating swap?

A. A fixed-for-floating swap is a contract between two parties under which one party agrees to swap a fixed price for a published index price on a notional quantity. A fixed-for-floating swap is economically equivalent to a fixed-price forward contract. The difference is that the fixed-for-floating swap is a purely financial instrument, while a forward contract generally anticipates physical delivery.

Q. What is a call option and how could it be used to mitigate price risk?

A. A call option gives its owner the right, but not the obligation, to buy an asset or commodity on a specified date (the expiration date), for a specified price (the

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[7] Southwest Airlines Co., 10-Q, October 20, 2006, p. 10.

strike price). HELCO-S-2404 illustrates the payouts that would accrue to the purchaser of a call option. Call options cap the price that will be paid by a buyer for a commodity.

HELCO-S-2404 shows the payouts that HELCO would incur/receive by fully hedging its fuel needs with a call option with a strike price of $70/bbl. Put simply, this strategy would cap the cost of oil at $70/bbl + the cost of the option (in $/bbl). If the strike price at the time of delivery proves to be less than $70/bbl, the call will produce no financial benefit and the cost of the strategy will be the cost of oil plus the cost of the option. If the price of oil proves to be above $70/bbl, revenues from the call option will completely compensate for any increases in the price HELCO pays for oil. Again, this exhibit does not capture basis risks.

Q. What is a collar and how does it limit risk?

A. A collar is a portfolio of options that are used to assure that the price of a commodity is within a given range. A buyer of a commodity who wishes to put a cap and floor on the price paid would sell a put option and buy a call option. This strategy assures that the price of the commodity will be within a given range – i.e., no lower than the strike price of the put (the floor) and no higher than the strike price of the call (the cap). HELCO-S-2405 shows the payouts that would accrue to the purchaser of a collar ignoring basis risks.

HELCO-S-2405 illustrates a collar using a call option with a strike price of $70/bbl and a put option with a strike price of $50/bbl. If the price of oil proves to be above $70/bbl, revenues from the call option will completely compensate for any increases in the price HELCO pays for oil. If the price of oil proves to be below $50/bbl, payments made to settle the put option will completely compensate for any decreases in the price HELCO pays for oil. Thus, HELCO's fuel costs will be between \$50/bbl and \$70/bbl.

SECTION 5: REALITIES OF THE MARKETPLACE

Q. Please describe any practical obstacles or constraints that HELCO would face if it were to enter the marketplace seeking to hedge on behalf of customers, that is, if it were seeking to limit the impact of fluctuations in world oil prices on customer rates.

A. I identify six important constraints that HELCO would face.

1. The first important constraint relates to the duration of the hedge. As I mentioned, the liquid forward and futures contracts that are traded in the marketplace do not extend beyond a term of 18 months. Further, the most liquid (*i.e.*, readily-available to trade) fuel hedging contracts are contracts that cover time periods of up to six months into the future. This is illustrated in HELCO-S-2401.

2. The second constraint faced by HELCO is that hedging contracts for the precise oil products and delivery points that HELCO would need are not visible in the marketplace. HELCO would therefore be exposed to considerable basis risks if it used the oil derivatives that are readily-available in the marketplace. It is possible that HELCO could obtain a customized swap agreement that hedges the price of the specific oil products in the specific locations that form the basis for the pricing formulas in HELCO's physical oil contracts. However, such a swap would be less transparent and it can be expected to be more expensive because the seller of such a swap would need to be remunerated for absorbing the basis risks and illiquidity of offering such a hedge. To illustrate the potential size of basis risks, I have shown the daily basis differential of the oil products that HELCO and its

affiliates (HECO and Maui Electric Company, "MECO") use relative to spot prices of oil products for which HELCO could obtain liquid hedges. These daily basis differentials are shown in HELCO-S-2406. Note that the price of the product which drives HELCO's costs is not exactly equal to the price of the product that would be hedged. This difference is basis risk. HELCO may hedge NYMEX WTI Crude futures, but if the WTI futures rise by $15 per barrel and the L.A. Bunker C fuel oil assessment in HELCO's WTI contracts rises by $20 per barrel, HELCO would not be hedged to the full extent. Similarly, if WTI futures rise $25 per barrel and the L.A. Bunker C fuel oil assessment in HELCO's contracts rises by $20 per barrel, the WTI hedge would overcompensate for the rise in the price of the L.A. Bunker C fuel oil assessment.

In addition, there is an issue of the incongruence of pricing dates relevant to the hedging commodity and the short commodity. Whereas HELCO's contracts for fuel are based on lagged thirty-day average prices, cash flows from hedging would be based on two days, the day on which the hedge is purchased and the settlement date (the last trading day before delivery). Thus, while the settlement date of a hedge will reflect price movements up to the day before delivery, the price of the short commodity will reflect markets 10 to 40 days earlier. Changes in the market during the forty-day period before the settlement date will affect the basis and cause the hedge to be less effective.

HELCO-S-2407 illustrates the magnitude of these basis changes. If the basis between the short commodity (the fuel burned by HELCO) and the hedge commodity (the futures used to hedge the short commodity) were constant, the ratio of the change in the hedge commodity to the change in the short commodity would be 1:1 = 100 percent. Instead, a historical "what if" analysis of fuel hedges shows that this ratio, or the effectiveness of the hedge, deviates greatly. For example, in 2003, yearly heating oil hedges moved 35.54 times in the *opposite* direction of the short commodity on an average basis. Thus, hedging strategies using these futures cannot be counted on to provide a reliable offset to movements in the price of the fuels burned by HELCO.

If HELCO were to look for alternatives, it would most likely be limited to customized products in the over-the-counter market. However, as mentioned above, prices for such products would most likely be less transparent and more expensive, which would increase costs and risks for customers.

3. The third constraint faced by HELCO is the quantity which it would hedge. The quantities that HELCO needs of each type of fuel fluctuate month to month and year to year in accordance with changing demand, availability and relative economics of generation plants, among other factors. HELCO's smaller size, relative to HECO, increases the significance of this constraint. HELCO's existing fuel contracts provide for flexibility on the quantities taken, subject to a minimum and maximum take. The quantity flexibility embedded in HELCO's existing fuel contracts would be difficult to match in the financial derivatives markets, which offer fixed quantity products. This quantity risk is important and makes hedging difficult. I have illustrated the variable quantities needed for each type of oil used by HELCO in HELCO-S-2408.

4. Fourth, if HELCO decides to engage in hedging, HELCO may face credit

risk. Credit risk is the risk of a financial loss associated with the failure of a party to perform on its obligations under a hedging contract. Credit risk is an important factor when considering fuel hedging contracts. Market practice is to mark forward contracts to market and to collateralize the credit exposure embedded in forward contracts. This means that the value of the contract is calculated every day and any exposure must be covered as margin. If HELCO engages in hedging, counterparties may require that HELCO provide collateral. The provision of collateral would add to the cost of hedging. Further, HELCO would in most instances be exposed to the risk of counterparty default and non-performance.

5. Fifth, the execution of fuel hedging contracts would expose HELCO to liquidity risks. Liquidity is the ability to execute transactions in the marketplace. Markets that are highly liquid have active trading and many buyers and sellers. Market liquidity for oil derivatives ebbs and flows. When the markets are less liquid, buyers and sellers may face difficulties entering into or exiting positions. Markets with low liquidity may inhibit HELCO's ability to execute or unwind hedge positions. In addition, low liquidity would harm HELCO's ability to replace a position as a result of counterparty default. Low liquidity also impedes the ability of a buyer to obtain a favorable price. The risk that these markets would not be liquid is a real one and could present significant price penalties and transaction constraints. Liquidity and its effect on price and the ease of making transactions should be fully understood and examined prior to HELCO's embarking on a hedging program.

6. Sixth, the contract sizes for the hedging instruments HELCO could use

(NYMEX WTI crude and heating oil) have minimum contract sizes of 1,000 bbls (42,000 gallons). Thus, a single contract may represent a significant percentage of HELCO's fuel obligation for a particular month. For example, in January 2005, HELCO took delivery of 17,700 bbls of diesel, less than in any other month that year. A 1,000 bbl heating oil contract corresponds to about 5.6 percent of this potential hedge. If HELCO were to pursue a hedging strategy separately from its larger affiliates,[8] its ability to effectively develop a portfolio of hedging instruments may be limited to an extent by the minimum contract size.

Q. Have you prepared a summary of the costs and risks for HELCO and its customers of entering into fuel hedging contracts?

A. Yes. This is shown in HELCO-S-2402. An analysis of whether the hedging alternatives that are available in the exchange and OTC markets are reasonable for HELCO to enter into must consider the risks shown in that exhibit. These factors indicate that HELCO's fuel costs will continue to fluctuate even if hedges are entered into due to risks that cannot be hedged. They also indicate that hedging will introduce new costs for customers that are not borne under the current regulatory regime.

Q. In considering these factors for HELCO, what are the most significant barriers to HELCO hedging oil to achieve a stable price?

A. Were HELCO to hedge using the most liquid products, it would face considerable basis risks. That is, the liquid, transparent and readily available hedges pose basis risk and would have limited hedge effectiveness. Again, basis risk arises from the change in prices of the hedge differing from the change in price of the actual

[8] HELCO's fuel and purchased power expenses represented on average 15 percent of the total HECO fuel and purchased power expenses over the 2001 to 2006.

physical commodity that HELCO purchases. Were HELCO to hedge using products with less basis risk, these products would be less liquid and less transparent. This is especially problematic for a regulated firm that must be able to demonstrate the reasonableness of its purchases. Neither buying less effective hedges nor buying less liquid and less transparent hedges is desirable as there are more effective means of achieving the same objective.

Q. Does this conclude your testimony?

A. Yes.

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Mr. Eugene Meehan is a Senior Vice President with NERA. He has over twenty-five years of experience consulting with electric and gas utilities. Mr. Meehan has testified as an expert witness before numerous state and federal regulatory agencies and appeared in federal court and arbitration proceedings.

His practice concentrates on serving NERA's energy industry clients, with a focus on helping clients manage the transition from the regulatory to a more competitive environment. Mr. Meehan has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. Mr. Meehan has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has led NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory strategy, business strategy and development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

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Education

Boston College, BA, Economics, cum laude
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	National Economic Research Associates
1999-Present	Senior Vice President
	National Economic Research Associates
1996-1999	Vice President
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President
	National Economic Research Associates, Inc.
1973-1980	Senior Economic Analyst, Research Assistant

Areas of Expertise

Restructuring/Stranded Cost Recovery: Mr. Meehan directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulation of regulatory filings to accomplish strategy. These assignments required facilitating sessions with senior management to set and track filing strategy. Clients included Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing: Mr. Meehan has formulated unbundling strategies, specializing in generation pricing. He has advised several utilities in standard offer pricing and testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement: Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation that had the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before the FERC and state regulatory agencies on competitive power procurement. Additionally Mr. Meehan helped design and implement the New Jersey BGS auction process.

Power Contracts: Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed in detail and testified on the three principal types of power contracts. These are integrated utility to integrated utility contracts, IPP to utility contract and integrated or wholesale utility to distribution utility contracts. He has testified in such contracts disputes on behalf of Carolina Power and

Light, Duke Power Company, Southern Company, Orange and Rockland Utilities and Tucson Electric Power. Amounts in dispute in these cases have ranged to $1 billion. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements: In addition to his expertise on power pooling issues, Mr. Meehan has recently devoted substantial efforts to assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets, designing efficient specifications for retail settlement systems including the use of load profiling, and examining the risk and cost allocation issues of alternative settlement systems.

Risk Management: Mr. Meehan has advised several large utilities in the area of price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements and provision of price managed service for various terms.

Marginal Costs: Mr. Meehan has been responsible for comprehensive marginal cost analysis for over twenty-five North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning: Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes and the prudence of particular investment decisions.

Generation Strategy: Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling: Mr. Meehan has an in-depth working knowledge of the operating, accounting and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since 1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability and marginal generating capacity cost quantification. In NEPOOL he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to examine the impact of PJM restructuring proposals upon generating asset valuation and to examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies and for various utilities on the impact of pooling arrangements on strategic alternatives. There is probably no other individual who is as familiar with as many pools and the variety of issues that these pools have encountered over the years.

Representative Assignments

Representative assignments, which Mr. Meehan directed for energy clients, include the following:

- Working with Public Service Electric & Gas Company (PSE&G), Mr. Meehan directed a three year NERA advisory effort on restructuring. Mr. Meehan facilitated a two day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998 Mr. Meehan worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination and

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briefing. He also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999 Mr. Meehan advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

- Working on separate assignments for a large utility in the Northeast and a large utility in the Southeast, Mr. Meehan advised on the evaluation of risk management offers from power marketers. The assignments included review of proposals, attendance of interviews with marketers and advice on these and the development of analytical software to evaluate offers.

- Working with government of Ontario beginning in 2004, Mr. Meehan helped design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. NERA, under Mr. Meehan's supervision will conduct the portfolio based economic evaluation on behalf of the Ontario Ministry of Energy.

- Mr. Meehan testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a to be created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. Additionally this effort involved the review of over 100 power contracts in the WECC.

- Mr. Meehan directed NERA's efforts for the electricity regulator in Ireland to design and RFP and implementation process fro the purchase of 500 Mw of new generating capacity. NERA advised on the RFP, the portfolio evaluation method and the power contract. Further NERA conducted the economic evaluation. This work was in 2003.

- Mr. Meehan reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Mr. Meehan submitted testimony before the FERC on behalf of Southern.

- Working with Baltimore Gas and Electric (BG&E) Mr. Meehan conducted a one and one-half year consulting effort advising on restructuring. Mr. Meehan began the project in March and April 1998, leading senior management discussions and workshops on plan development and filing strategy. He advised BG&E in the development of testimony, rebuttal testimony and public information dissemination. Mr. Meehan worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits. He also offered testimony in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, Mr. Meehan advised BG&E on generation valuation and unregulated generation business strategy.

- Mr. Meehan has directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards and unit contracts to determine the optimal mix of instruments to manage price risk.

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- Mr. Meehan recently testified for XCEL Energy on the use of competitive bids for new generation needs. The issue addressed by Mr. Meehan involved an examination of whether the Company was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life of facility contracts in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

- Mr. Meehan advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. He defended the First Energy shopping credit proposal.

- Mr. Meehan advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. The subject of his testimony was retail competition in gas and electric commodity markets.

- Mr. Meehan directed NERA's effort to train selected representatives of a major European power company in the United States power marketing and risk management practices. The project involved numerous visits and interviews with power marketing firms.

- Mr. Meehan has led NERA effort to advise the New England ISO on the development of an RTO filing. This work has involved an examination of performance-based ratemaking for transmission and market operator functions.

- Mr. Meehan examined ERCOT power market conditions during the 1997 to 1999 period and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

- Mr. Meehan has advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. The issues involve forecasting of the unbundled wholesale cost of service and forecasts of market prices as well as development of a regulatory strategy for gaining approval of contract restructuring and the transferring of generation from regulated to EWG states.

- Mr. Meehan has performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

- Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions and recommendations concerning credit exposure monitoring, credit evaluation processes and credit requirements.

- Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, portion of the U.K. wholesale settlement system.

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- Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members, and the evolution of full requirement power wholesale power contracts into contracts that preserved Oglethorpe's financial integrity and were suitable for a competitive environment.

- Development of long run marginal and avoided costs of natural gas service and avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

- Review of power contracts and testimony in numerous power contract disputes.

- Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM, cogeneration, and in the development of integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

- Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first such in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

- Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presentation of strategic and financial results helped convince senior management to initiate negotiations for the incentive plan.

- Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP based marginal capacity costs.

- Provided testimony on behalf of the investor-owned electric utilities in New York state concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

- Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

- Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool for various consulting assignments and in connection with the development of production simulation software.

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- Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

- Developed and presented a two-day seminar delivered to electric industry participants in the United Kingdom, prior to privatization, outlining the structure and operation of power pools and bulk power market transactions in North America.

- Benchmark analysis and FERC testimony of PGE's proposed twelve year contract between PG&E and Electric Gen LLC including contract value in excess of $15 billion.

- Responsible for NERA's overall efforts with respect to advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions. The 2002 auction was over $3.5 billion and the 2003 and 2004 auction were for over $4.0 billion.

Expert Testimony
Mr. Meehan has provided expert testimony in the following forums:

- Arkansas Public Service Commission
- Federal Energy Regulatory Commission
- Florida Public Service Commission
- Maine Public Utilities Commission
- Minnesota Public Service Commission
- Nevada Public Service Commission
- New York Public Service Commission
- Nuclear Regulatory Commission – Atomic Safety and Licensing Board
- Oklahoma Public Service Commission
- Public Service Commission of Indiana
- Public Utilities Commission of Ohio
- Public Utilities Commission of Nevada
- Public Utilities Commission of Texas
- Public Utilities Commission of New Hampshire
- Colorado Public Utilities Commission
- United States District Court

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- United States Senate Committee on Energy and Natural Resources
- Various arbitration proceedings

Clients on whose behalf Mr. Meehan has testified include

- Arkansas Power & Light Company
- Baltimore Gas & Electric
- Carolina Power & Light Company
- Central Maine Power
- Consolidated Edison Company of New York, Inc.
- Dayton Power and Light Company
- Florida Coordinating Group
- Houston Lighting & Power Company
- Minnesota Power and Light Company
- Nevada Power Company
- Niagara Mohawk Power Corporation
- Northern Indiana Public Service Company
- Oglethorpe Power Corporation
- Pacific Gas and Electric Company
- Power Authority of the State of New York
- Public Service and Electric Company
- Public Service Company of Oklahoma
- Sierra Pacific Power Company
- Southern Company Services, Inc.
- Tucson Electric Power Company
- Texas-New Mexico Power Company

Specific List of Recent Expert Testimonies and Expert Reports

- Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996

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- Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997
- Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998
- Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999
- Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999
- Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999
- NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.
- Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999
- Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999
- Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999
- Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999
- Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999
- Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits
- Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000
- Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000
- Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000
- Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000
- Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000
- Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001

Eugene T. Meehan
National Economic Research Associates, Inc.

- DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00. August 27, 2001
- State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001
- Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001
- Fourth Branch Associates/Mechanicville Vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).
- Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002
- Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002
- Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003
- Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003
- Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003
- Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003
- Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the Public Service Commission of New York, Case No.: 00-E-0612, September 19, 2003
- State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) September 2003

Eugene T. Meehan
National Economic Research Associates, Inc.

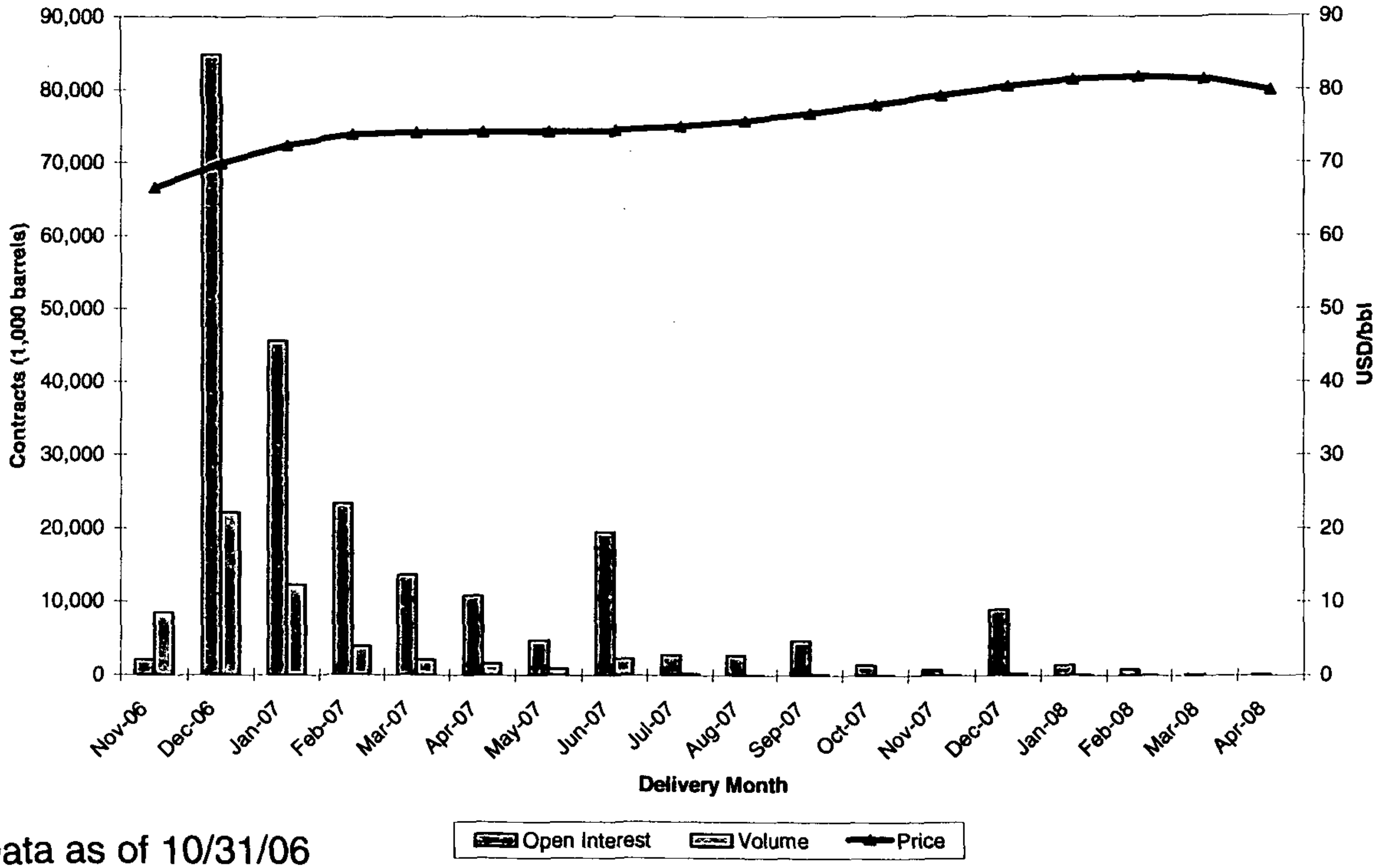
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004
- Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004
- Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004
- Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004
- State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) September 2004
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005
- Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005
- Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005
- Remand Rebuttal Testimony for Public Service Company of Oklahoma, Cause No. PUD 200200038, March 17, 2006
- Answer Testimony on behalf of the Colorado Independent Energy Association, AES Corporation and LS Power Associates, L.P., Docket No. 05A-543E, April 18, 2006
- Cross-Answer Testimony on behalf of the Colorado Independent Energy Association, AES Corporation and LS Power Associates, L.P., Docket No. 05A-543E, May 22, 2006

May 2006

HELCO-S-2401
LIQUIDITY CHARTS
FOR 3 FUTURES HEDGES (1 of 2)

NERA
Economic Consulting

Heating Oil Forward Curve and Liquidity



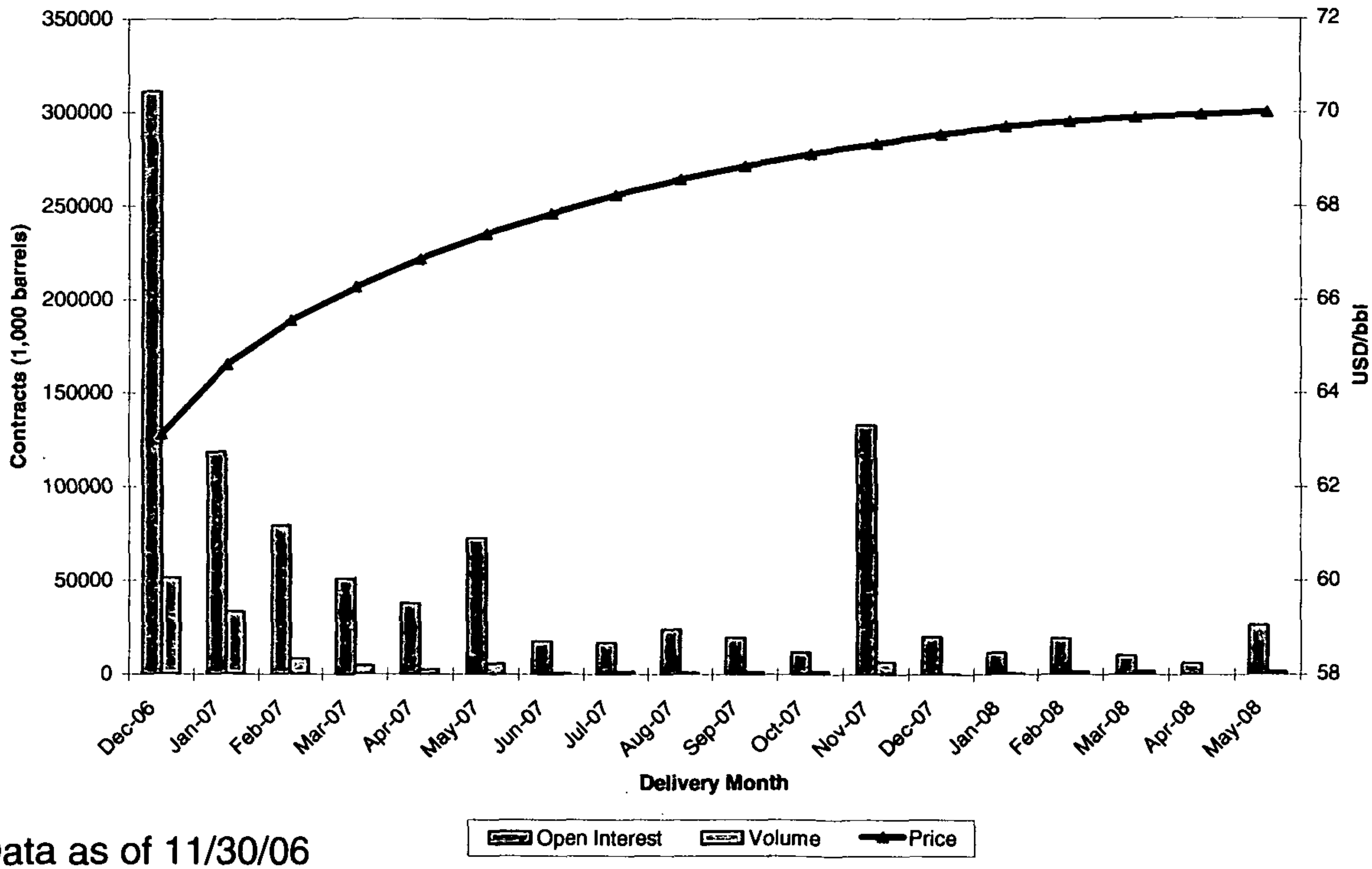
Data as of 10/31/06

HELCO-S-2401
DOCKET NO. 05-0315
PAGE 1 OF 2

HELCO-S-2401 LIQUIDITY CHARTS FOR 3 FUTURES HEDGES (2 of 2)

NERA Economic Consulting

WTI Forward Curve and Liquidity



Data as of 11/30/06

HELCO-S-2401
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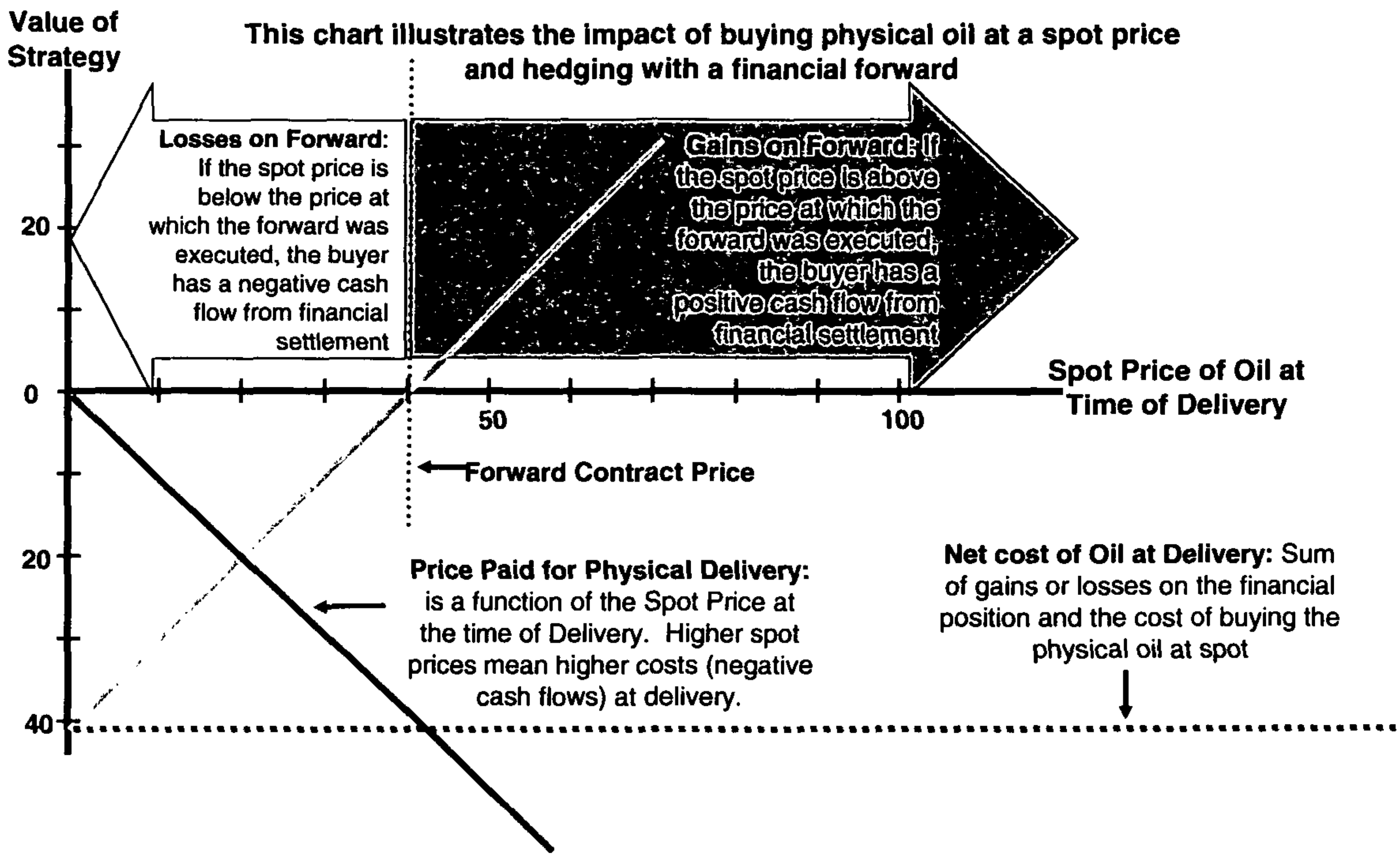
HELCO-S-2402
COSTS AND RISKS OF HEDGING

NERA Economic Consulting

Cost	Administrative cost	Cost of collateral postings Compliance with hedge accounting rules. Up-front regulatory costs (cost of establishing hedging objective and hedging program including execution timeframe, contract types, contract duration) Ongoing regulatory costs (costs of obtaining periodic regulatory pass through of hedging costs)
Risk	Market risks	Market risks on incremental/decremental quantities Basis risk. Difference in prices of hedge commodity and short commodity spread widens or contracts, thus reducing the effectiveness of the hedge
Risk	Credit risks	Counterparty default risk
Risk	Liquidity risks	Ability to unwind or replace positions
Risk	Duration of hedge	Increases market, credit and liquidity risks

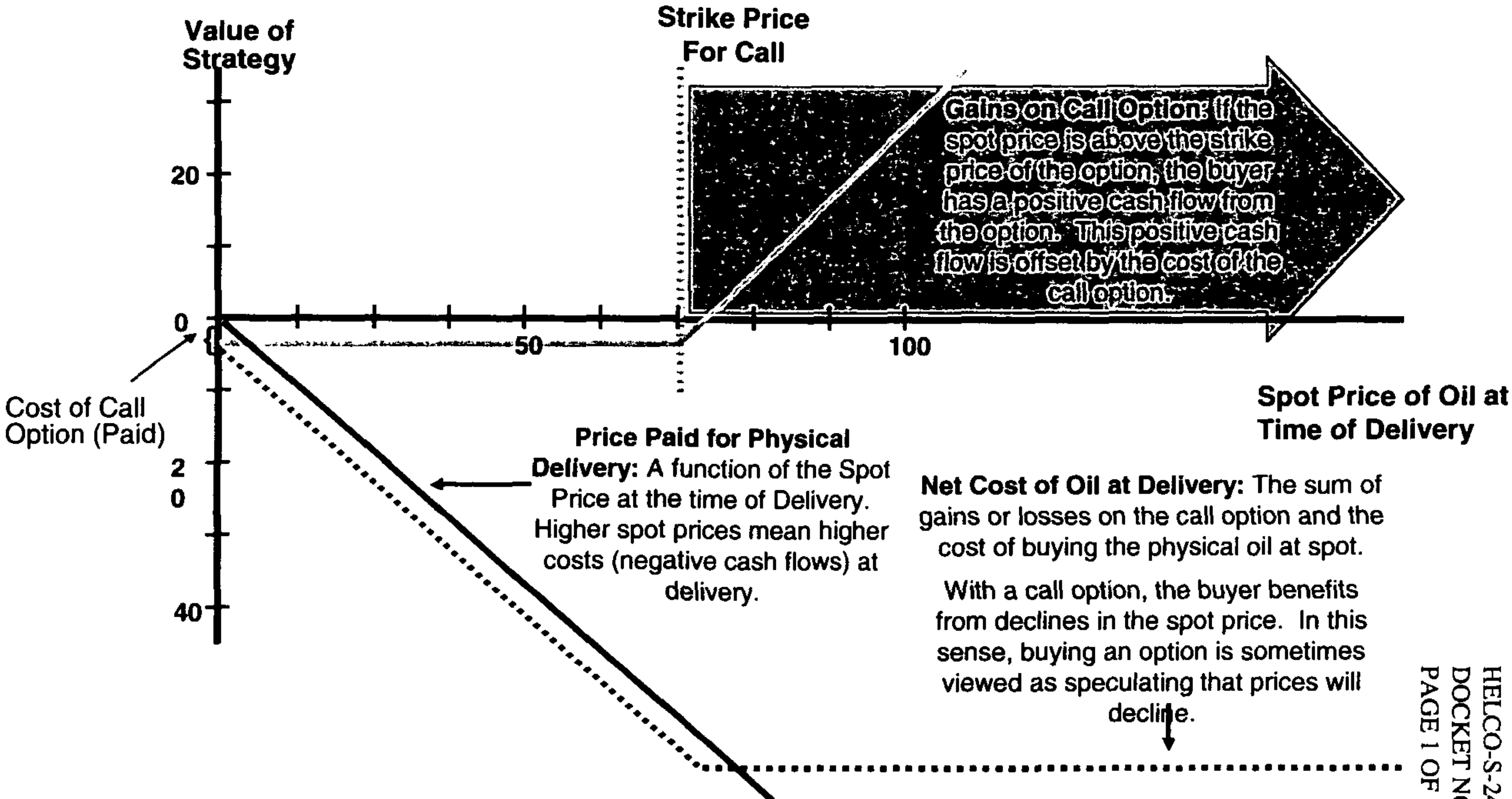
HELCO-S-2403
Payout Diagram – Buyer Enters into Fixed-price Forward (no basis)

NERA Economic Consulting



A forward contract fixes the cost of the commodity for the buyer

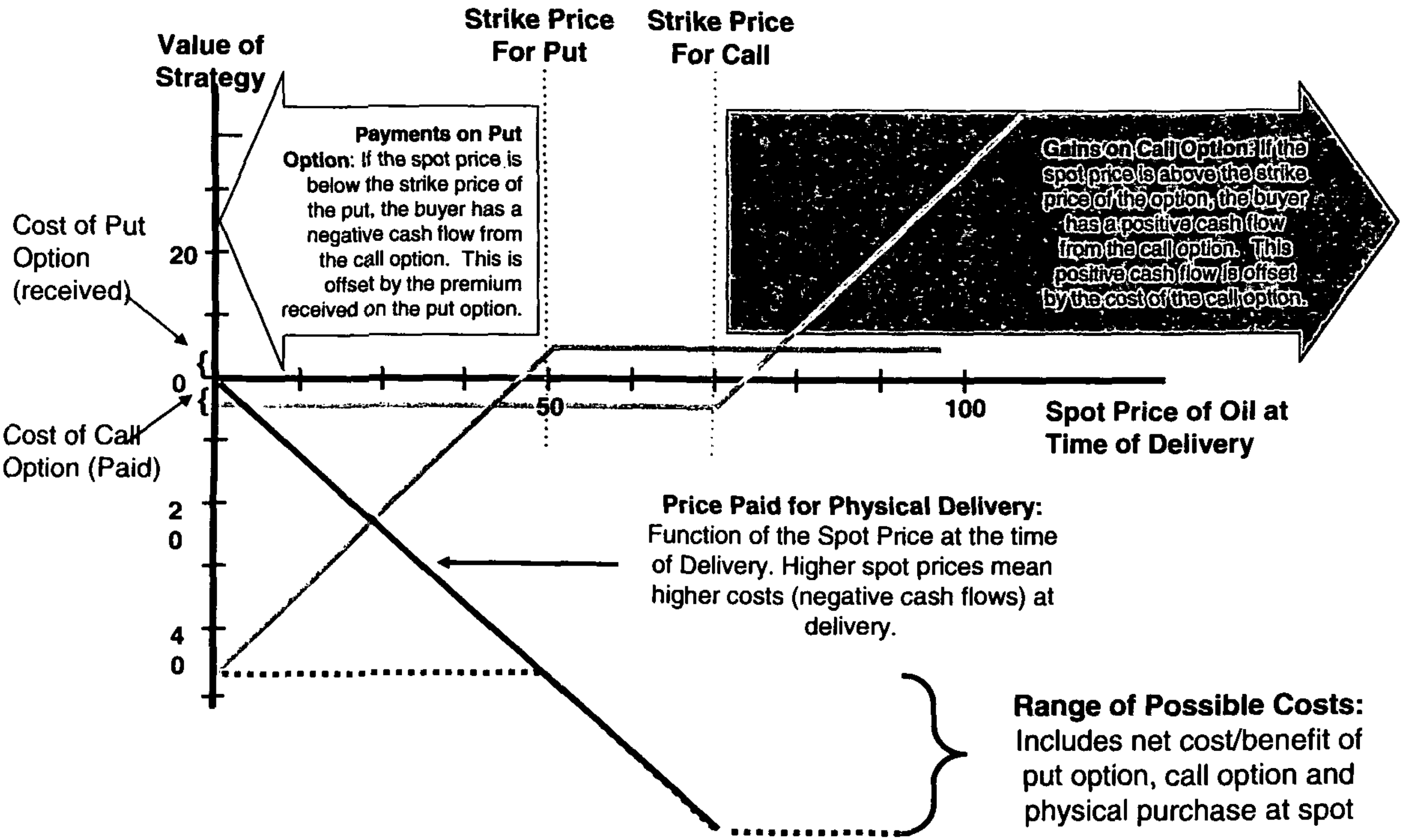
HELCO-S-2404
Payout Diagram – Buyer Enters into Call Option Contract (no basis)



A call option puts a cap on the cost of the commodity for the buyer

HELCO-S-2405
Payout Diagram – Buyer Enters into Collar (no basis)

NERA Economic Consulting



A collar puts a cap and a floor on the cost of the commodity for the buyer

HELCO-S-2405
DOCKET NO. 05-0315
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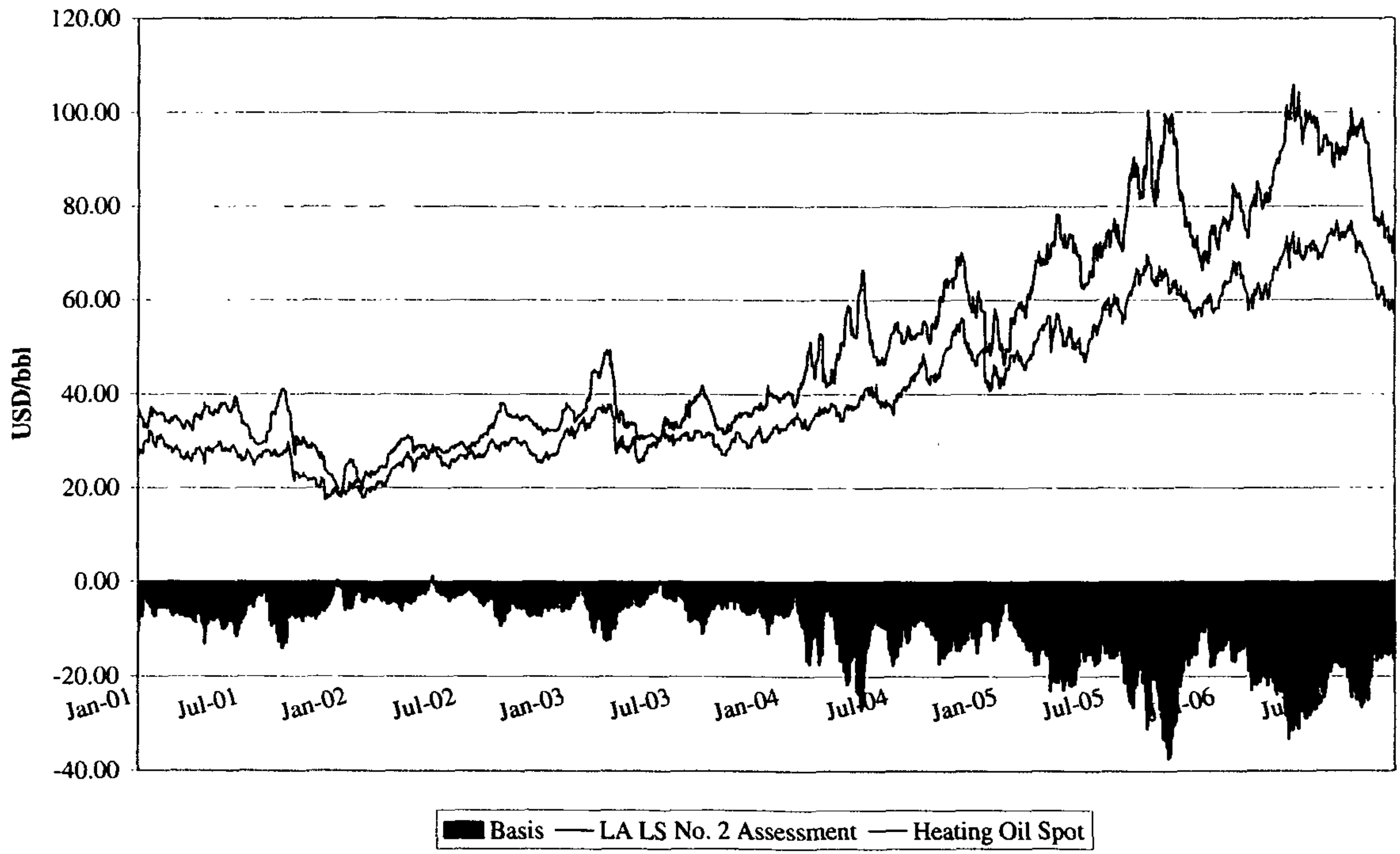
HELCO-S-2406
HISTORIC BASIS GRAPHS (1 of 2)

NERA Economic Consulting

Basis: Heating Oil and LA LS No. 2



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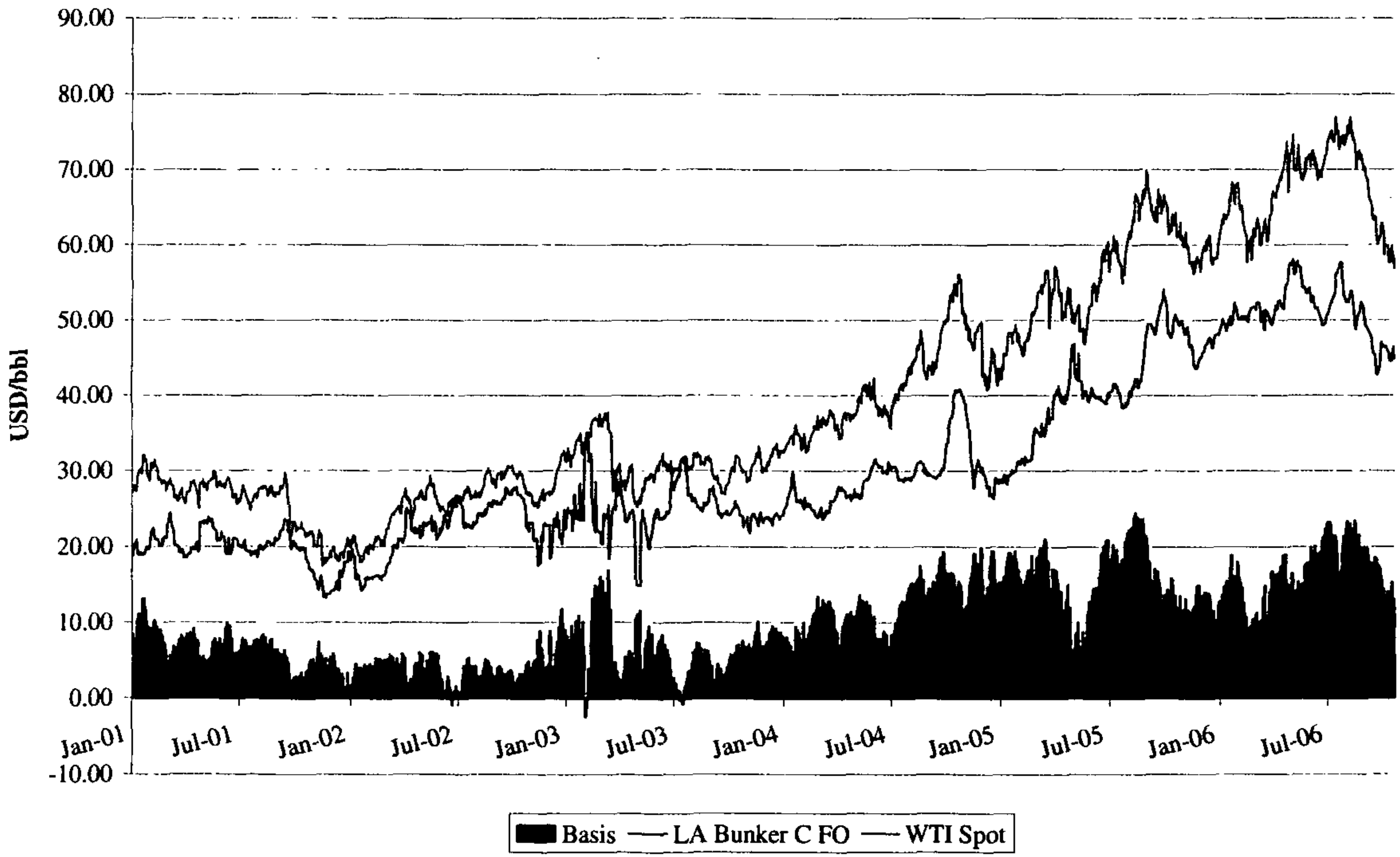
HELCO-S-2406
HISTORIC BASIS GRAPHS (2 of 2)

NERA Economic Consulting

Basis: WTI and LA Bunker C



HELCO-S-2406
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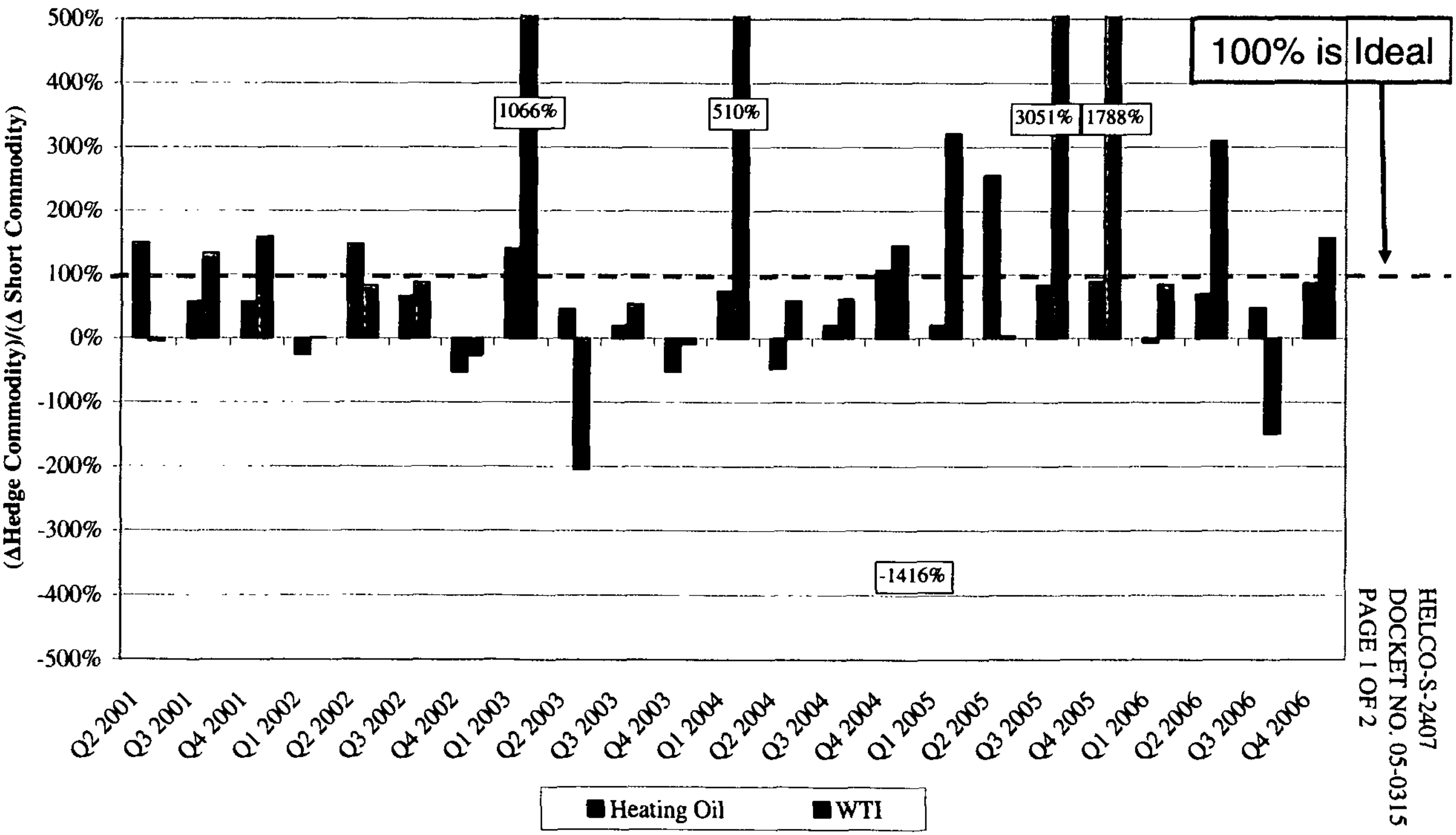
HELCO-S-2407
HEDGE EFFECTIVENESS (1 of 2)

NERA Economic Consulting

Effectiveness of Quarterly Hedges



HELCO-S-2407
DOCKET NO. 05-0315
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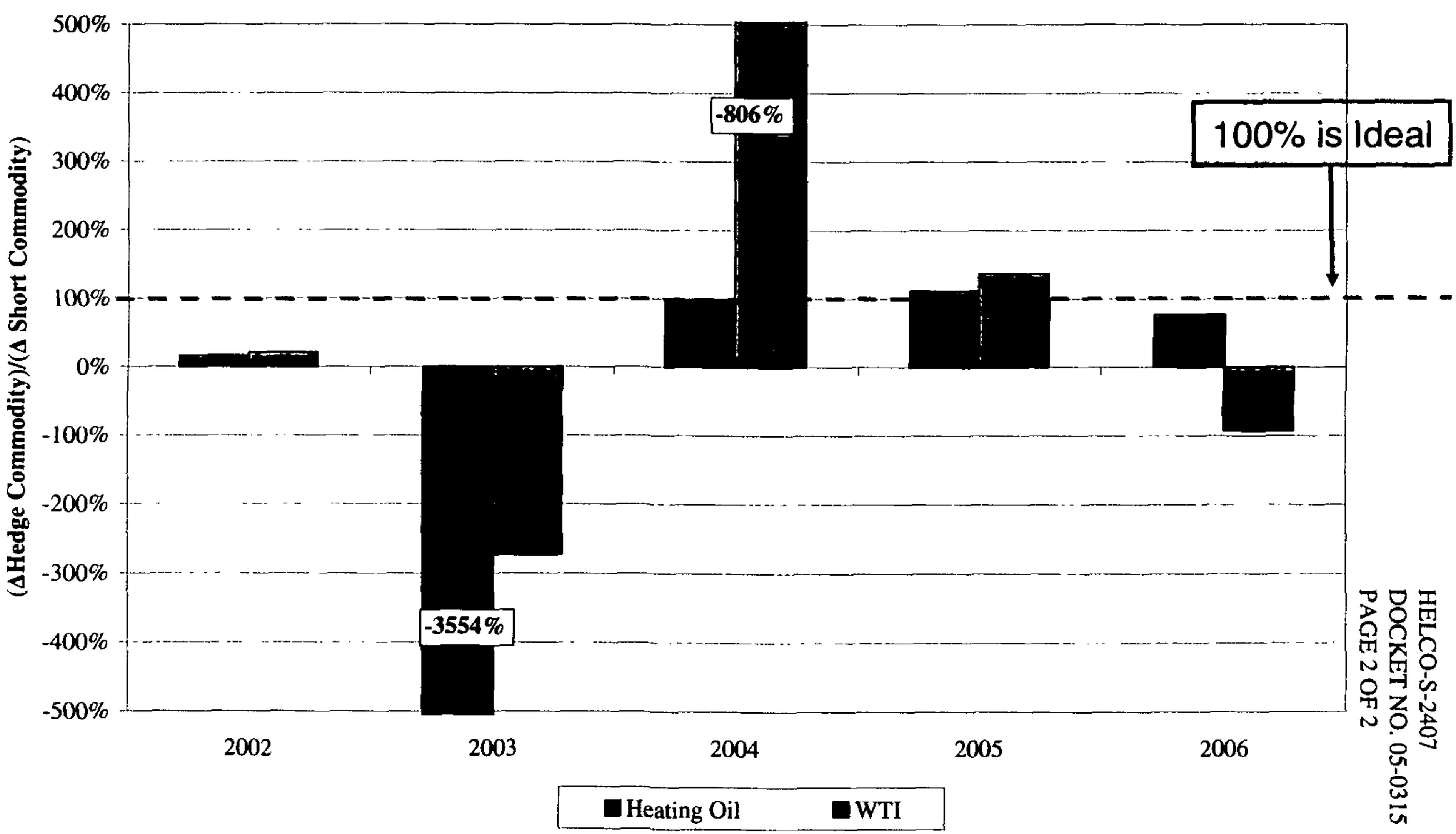
HELCO-S-2407
HEDGE EFFECTIVENESS (2 of 2)

NERA Economic Consulting

Effectiveness of Yearly Hedges

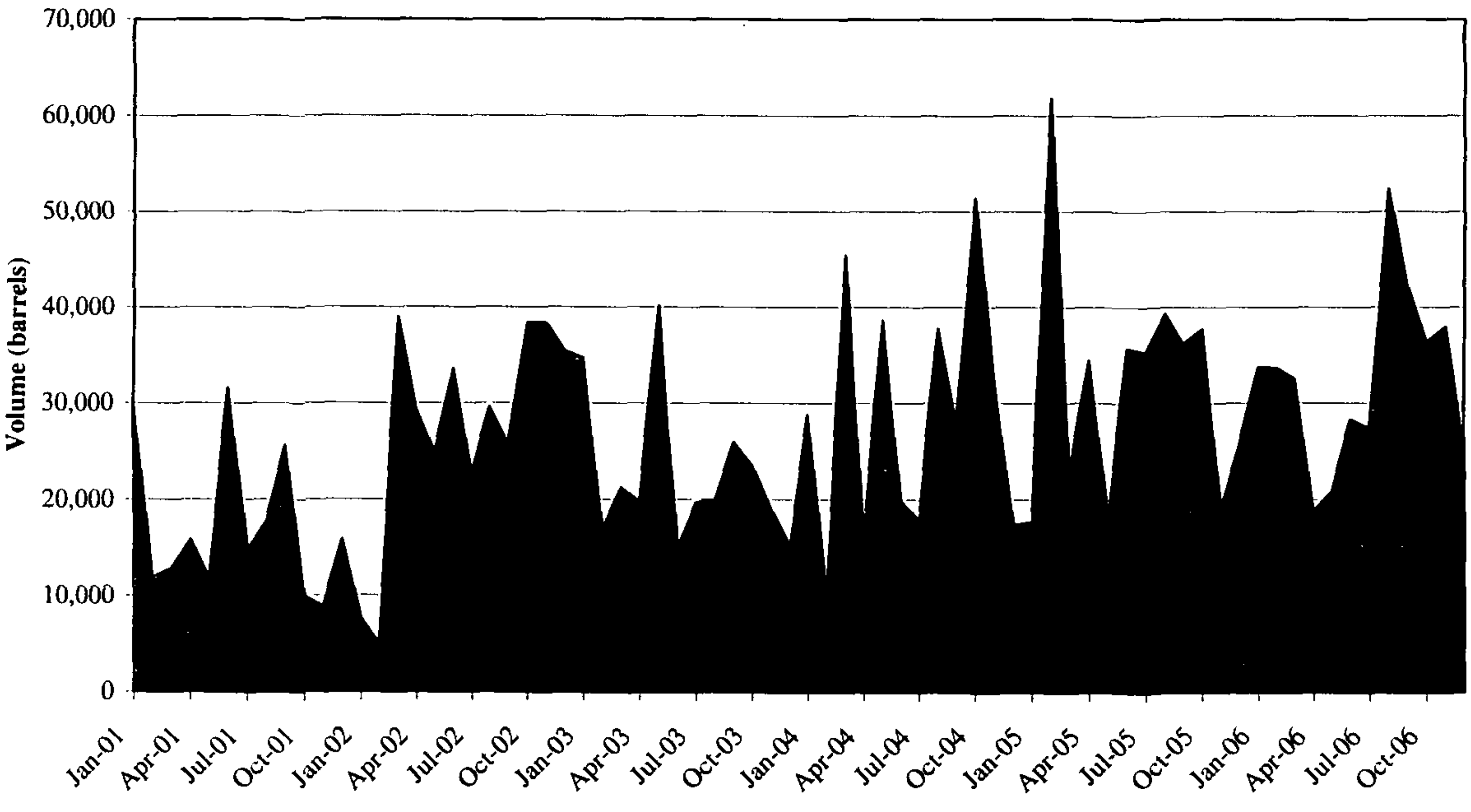


HELCO-S-2407
DOCKET NO. 05-0315
PAGE 2 OF 2

HELCO-S-2408
HISTORIC QUANTITIES DELIVERED FOR EACH FUEL (1 of 2)

NERA
Economic Consulting

Diesel Oil Deliveries

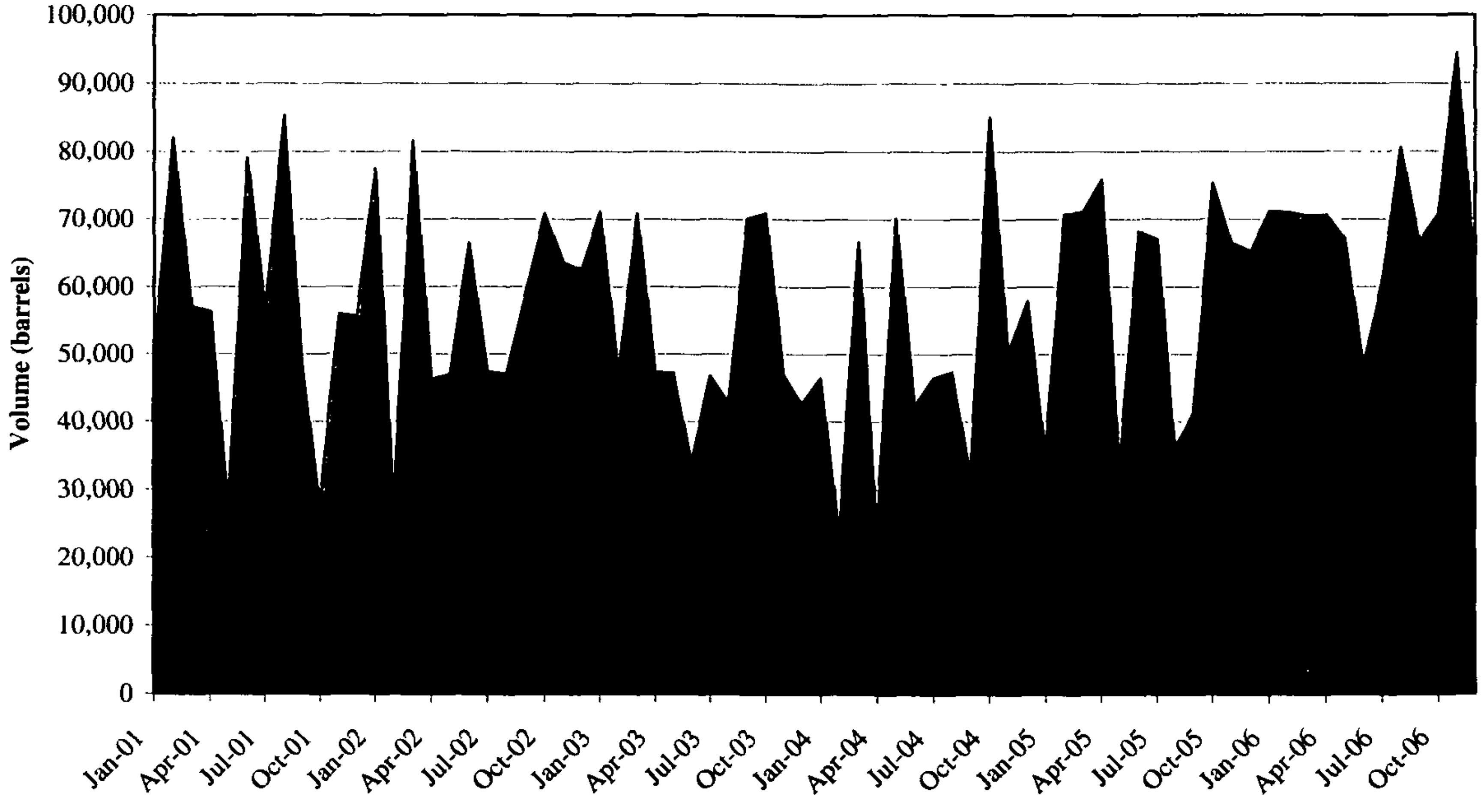


Reflects deliveries for HELCO only.

HELCO-S-2408
HISTORIC QUANTITIES DELIVERED FOR EACH FUEL (2 of 2)

NERA Economic Consulting

Industrial Fuel Oil Deliveries



Reflects deliveries for HELCO only.

HELCO ST-18
DOCKET NO. 05-0315

SUPPLEMENTAL TESTIMONY OF
TAYNE S. Y. SEKIMURA

FINANCIAL VICE PRESIDENT

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Rate of Return on Rate Base

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and I am the Financial Vice President of Hawaii Electric Light Company, Inc. ("HELCO" or the "Company"). My business address is 900 Richards Street, Honolulu, Hawaii, 96813.

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as HELCO T-18.

Q. What is the purpose of this supplemental testimony?

A. The purpose of this supplemental testimony is to address the potential changes in the energy cost adjustment clause ("ECAC") and the impact of Act 162[1] on investors. Act 162 added a provision in Hawaii Revised Statutes ("HRS") 269-16 which states:

> Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:
> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;
> (3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
> (4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and
> (5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

Q. Please briefly describe the Company's existing ECAC mechanism.

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[1] Act 162 was passed by the State Legislature in the 2006 Legislative Session and signed into law by the Governor on June 2, 2006.

A. The ECAC is an automatic adjustment provision in the utility's rate schedules that allows the utility (through the application of the "ECA factor") to automatically increase or decrease charges to reflect the change in the Company's costs of fuel and purchased energy above or below the levels included in the base charges without a rate proceeding. A rate case proceeding determines the base electricity rates into which are embedded test year levels of fuel prices, payment rates for purchased energy and a test year resource mix. The ECAC mechanism, expressed in cents per kilowatt-hour, allows the Company to recover/return costs due to subsequent changes in (1) fuel and purchased energy costs, (2) the resource mix between utility-owned generation, utility-DG and purchased energy, (3) the resource mix among the utility plants, and (4) the resource mix among purchased energy producers. A rate proceeding also establishes a fixed efficiency factor, or sales heat rate, for the utility central station generation, which provides an incentive to operate the units as efficiently as possible. The ECA factor is filed with the Commission monthly and sets the rate adjustment for the subsequent month. See Mr. Young's discussion in HELCO T-3.

Q. Please describe the investor perspective of the Company's existing ECAC mechanism.

A. HELCO's investors view the Company's existing ECAC mechanism very favorably because it significantly reduces the Company's business risks. Dependence on imported fuel oil and the associated fuel price fluctuation are significant risks to the Company. The monthly revenue adjustment for fuel and purchased energy price changes results in timely recovery of fuel oil and purchased energy costs which significantly reduces the business risk profile. Thus, the existing ECAC has a positive credit quality impact.

In its credit assessment of HELCO's parent company, Hawaiian Electric Company, Inc. ("HECO")[2], S&P has in the past cited "an excellent fuel adjustment clause" as strengthening credit quality in part offsetting "reliance on fuel oil", "significant purchased power obligations", and "high prices" which weaken credit quality.

Q. Has Act 162 resulted in any change in investor concerns relating to the Company's fuel and purchased power expenses?

A. Yes. The Company's investors are clearly concerned by the legislative action. In its credit assessment of HECO dated November 22, 2006[3], S&P stated in part:

> Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile.

Q. Are there other investor risks associated with fuel and purchased power?

A. Yes. As noted in my direct testimony, the Company has significant purchased power obligations which are considered in evaluations of our credit. The reliance on purchased power creates debt-like obligations which are of concern to investors. Further there have been changes in the accounting treatment of the purchased power obligations and there is uncertainty as to how these changes may impact investor views of these obligations. I discussed the impact of purchased power on the Company's credit quality in greater detail in my direct testimony.

Second, the Company is exposed to financial variability due to changes in fuel efficiency. In a rate case proceeding, fuel expense is established based on

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[2] See Direct Testimony HELCO T-18, page 8 for discussion of the relationship of HELCO and HECO credit ratings.

[3] See S&P Ratings Direct filed as Exhibit HELCO-S-1801.

fuel efficiency factors which are embedded in base electric rates. Ms. Giang provides a complete description of the fuel efficiency factor calculation in HELCO T-4. When actual heat rates are lower (better) than the heat rates embedded in base rates, fuel expense is lower and returns to shareholders are higher. When actual heat rates are higher (worse) than the heat rates embedded in base rates, fuel expense is higher and returns to shareholders are lower. This gives management incentive to optimize the generation dispatch and to maintain and operate the Company-owned generation to maximize fuel efficiency.

Finally, the Company bears the costs or enjoys the benefits from cost savings resulting from changes in the carrying costs of fuel inventory. The cost of fuel inventory fluctuates as fuel prices fluctuate. Higher fuel prices result in higher inventory cost and higher costs of carrying inventory which reduces returns to shareholders. Conversely, lower fuel prices result in lower inventory cost and lower costs of carrying inventory which contribute to shareholder returns. There is not much near-term management control over these carrying costs since inventory volumes are constrained by operational requirements and inventory price is determined by the indexed fuel prices embedded in long-term fuel purchase contracts. However, since the absolute amounts of inventory carrying costs are relatively small, this risk is not viewed as a significant business risk from an investor's perspective.

Q. How are investors currently compensated for the risks that they take relating to fuel and purchased power?

A. In general, investors are not specifically compensated for the risks they take relating to fuel. Although dependence on imported fuel oil increases business risks, the existing ECAC mechanism significantly mitigates this risk. The risks associated with changes in the fuel inventory carrying costs are generally not significant from an investor's perspective and investors do earn a return on the fuel inventory included in rate base.

Investor risks associated with purchased power are considered in establishing the appropriate rate of return on equity. In HELCO T-17, Dr. Morin discusses the need for shareholder compensation resulting from purchased power.

Q. Does the design of the current ECAC mechanism "fairly share the risk of fuel cost changes between the public utility and its customers"[4]?

A. Yes. As discussed by Dr. Makholm in HELCO ST-23 (and Mr. Hee in HELCO ST-22), fuel cost changes include fuel price changes and fuel efficiency changes. Under the existing ECAC, customers generally bear the risk of fuel price changes and shareholders generally bear the risk of fuel efficiency changes. Customers pay less when actual fuel prices decline, and customers pay more when actual fuel prices escalate. In establishing a fair rate of return on equity, the Company's current ECAC is assumed to continue (see Dr. Morin's discussion in HELCO T-17). The concept that shareholders do not make any profit from fuel price changes is therefore embedded in the return on equity recommendation. This is "fair" because shareholders do not require compensation for risks that they do not bear.

Q. How is it "fair" that customers bear nearly all the risks and shareholders take minimal risks associated with fuel price changes?

A. It is "fair" because the required rate of return on common equity is relatively lower due to the fact that shareholders take minimal risks associated with fuel price changes. As a result, customers benefit by having lower electric rates that

[4] HRS Section 269-16(g)(1).

are based on the relatively lower rate of return on common equity.

Q. If customers pay less when actual fuel prices decline, why does the ECAC revenue have a recent history of being positive (i.e., customers pay more than base rates)?

A. The fuel oil prices used to establish base rates set the "base" in determining whether ECAC is positive or negative. Since under the current ECAC customers will bear nearly all the costs associated with fuel price changes, it does not matter what portion of the fuel cost is reflected in base rates and what portion gets reflected in ECAC. In prior rate cases, the Company and the Consumer Advocate were able to agree on fuel price estimates, since the ECAC will adjust revenues to reflect the actual cost of fuel.

Also, currently, fuel price is not a driver for determining when a rate case is needed. If base rates are set at a time when fuel prices are relatively low, the ECAC will be positive when fuel prices rise. Conversely, if base rates are set at a time when fuel prices are relatively high, the ECAC will be negative when fuel prices drop.

Q. Does the design of the current ECAC mechanism "preserve, to the extent reasonably possible, the public utility's financial integrity"[5]?

A. Yes. The current ECAC mechanism is a strength in HECO's business risk profile and contributes to HELCO and HECO's financial integrity. The monthly adjustment of the existing ECAC also minimizes the recovery time period, further reducing investor uncertainty with respect to recovery of fuel costs.

As I mentioned earlier, S&P has often cited the existing ECAC mechanism as a strength in HECO's credit quality assessment. Conversely, the potential to

[5] HRS Section 269-16(g)(4).

change the existing ECAC has raised concerns with the rating agencies as noted in S&P's credit assessment of HECO dated November 22, 2006 in Exhibit HELCO-ST-1801.

Q. Does the design of the current ECAC mechanism "minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs"[6]?

A. Yes. The current ECAC design virtually eliminates fuel price changes as a consideration as to when a rate case is necessary.

Q. Are there any alternatives to changing the existing ECAC mechanism if the objective is to "smooth" the impact of fuel price changes on electricity bills?

A. Continuation of the existing ECAC is essential to maintaining the financial integrity of the Company; however, the Company recognizes that volatile fuel prices negatively impact our customers and therefore will consider other means of smoothing the impact of fuel price changes on customers. Dr. Makholm discusses budget billing and fixed rate billing mechanisms in HELCO ST-23.

Q. Has the Company considered implementing a fuel price hedging program?

A. Yes. The Company retained the consulting services of National Economic Research Associates, Inc. ("NERA") to evaluate the issues associated with implementing a fuel price hedging program. Their findings relating to hedging options are summarized by Mr. Meehan in HELCO ST-24.

Q. Does the Company propose to implement a fuel price hedging program?

A. No. The Company is not proposing to implement a fuel price hedging program at this time. Mr. Meehan details the numerous considerations that must be addressed before a fuel hedging program can be implemented. As Mr. Hee indicates in

[6] HRS Section 269-16(g)(5).

HELCO ST-22, the Company will be exploring budget billing and fixed rate billing options to address rate smoothing.

Q. What would be necessary if any new or modified fuel cost recovery mechanism is implemented in order to "fairly share the risk of fuel cost changes between the public utility and its customers" and to "preserve, to the extent reasonably possible, the public utility's financial integrity"?

A. Any new or modified fuel cost recovery mechanism that results in increasing investors' risks associated with fuel and/or purchased energy would require an increase in investor compensation through a higher cost of capital for bearing the increased risks. Customers would ultimately bear the higher costs for this increase in cost of capital. See Dr. Morin's discussion in HELCO T-17.

Q. What are your conclusions with respect to the ECAC?

A. The existing ECAC is a significant rate adjusting mechanism which helps HECO to maintain its current standing with investors. Fuel and purchased power costs are a significant portion of HELCO's expenses and therefore have tremendous potential financial impact. It is essential that the potential creditor and shareholder implications of any change to the ECAC be carefully and thoroughly considered before implementation.

Q. Does this conclude your testimony?

A. Yes.

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Summary:

Hawaiian Electric Company, Inc.

Publication date: 22-Nov-2006
Primary Credit Analyst: Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Credit Rating: BBB+/Negative/A-2

Rationale

The ratings on Hawaiian Electric Co. Inc. are based on the consolidated credit profile of Hawaiian Electric Industries, Inc. (HEI), which includes Hawaiian Electric's utility operations and its two subsidiaries Hawaiian Electric Light Co. (HELCO) and Maui Electric Co. (82% of core revenues and 61% of operating income as of Dec. 31, 2005), and the riskier financial services operations of American Savings Bank FSB, (18% of core revenues and 39% of operating income). Standard & Poor's Ratings Services does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

HEI's consolidated financial condition remains somewhat weak for the rating despite the strong Hawaiian economy and the company's efforts in recent years to strengthen its capital structure. On a stand-alone basis, Hawaiian Electric has a healthier financial profile owing to a lower debt burden. Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, the prolonged lack of rate relief, and recently, lower electricity sales caused by cooler less humid weather and customer conservation. Absent a responsive final rate order in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI and Hawaiian Electric have satisfactory business profiles of '6' and '5', respectively, (business profiles are ranked from '1' (excellent) to '10' (vulnerable)) and somewhat weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, a currently excellent fuel clause, and relatively steady banking operations. The bank's decent earnings are driven by net interest income from its low-risk earning-asset base, funded largely by a good deposit franchise. These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, significant purchased power obligations, and support of the somewhat riskier banking business. Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations.

A responsive final rate order from the Hawaii Public Utilities Commission (PUC) with regard to Hawaiian Electric's pending rate case is crucial to help lift key financial measures to more appropriate levels for the ratings. In September 2005, the PUC issued an interim net rate hike of $41.1 million (3.3%) that is marginally supportive of current ratings. If the amount collected under the interim increase exceeds the amount of the increase ultimately approved in the PUC's final decision and order, the company must refund the excess to its ratepayers with interest. A final order that closely mirrors the interim ruling appears to be sufficient to lift key financial metrics to levels that are marginally suitable for Standard & Poor's guideposts for the 'BBB' rating category. There are no time restrictions in which the PUC must issue a final order. Furthermore, pending before the PUC is HELCO's request for a $29.9 million (9.2%) rate increase. An interim decision is expected in the second quarter of 2007.

Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile.

Hawaii's economy grew by about 3.4% in 2005 and is expected to grow by 2.7% in 2006. Military and federal government spending remains strong as the U.S. Department of Defense has moved military assets to Hawaii. Tourism is also a significant component of the Hawaii economy, with visitor days and visitor expenditures up 7.7% and 9.6%, respectively in 2005. Continued growth is expected in 2006, with projected increases of 2.8% in visitor days and 7.1% in visitor expenditures. Although the housing market appears to be stabilizing, the construction industry continues to be healthy. However, future growth in residential construction may slow with rising interest rates. Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

Hawaiian Electric's projected $912 million capital outlays over the next five years will focus predominantly on additions and improvements to transmission and distribution facilities (approximately 51%) and on generation projects (approximately 41%). The balance is for general plant, energy solutions, and customer-choice technologies. Although the bulk of construction expenditures will continue to be funded internally, the company's larger investment in reliability projects will result in increased reliance on outside capital.

HEI has certain bondholder protection metrics that are subpar for the current ratings. In this regard, total debt to capital (adjusted for off-balance-sheet obligations, such as purchased-power contracts and trust-originated preferred securities) and funds from operations (FFO) to total debt are somewhat weak at about 57% and 17%, respectively. Adjusted FFO interest coverage remains healthy at roughly 3.8. Accordingly, a supportive final rate order, tight cost controls, improved earnings, and credit supportive actions by management will be required to lift the company's overall financial profile to more suitable levels.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating solid liquidity, a manageable maturity ladder, and the ability to internally fund a large portion of dividends and capital expenditures in nearby years.

HEI maintains a $100 million unsecured revolving credit facility that expires on March 31, 2011. The covenants require HEI to maintain a nonconsolidated capitalization ratio of 50% or less and consolidated net worth of $850 million. The company is comfortably in compliance with these covenants. HEI used the aforementioned facility to support the issuance of commercial paper to refinance its $100 million of medium-term notes which matured on April 10, 2006. In August 2006, HEI permanently funded the maturity with medium-term notes and terminated a $75 million unsecured bilateral revolver. Effective April 3, 2006, Hawaiian Electric entered into a $175 million revolver that expires on March 29, 2007, but will automatically extend to five years if the longer-term agreement is approved by the PUC. Pursuant to the agreement, the company must maintain a consolidated common stock equity to capitalization ratio of at least 35%, with which the company is in compliance.

Both HEI's and Hawaiian Electric's facilities support the issuance of commercial paper, but may also be drawn for general corporate purposes. Hawaiian Electric's facility may also be drawn for capital expenditures. The facilities do not contain interest coverage ratio requirements, material adverse change clauses, nor rating triggers. As of Oct. 31, 2006, both HEI's and Hawaiian Electric's credit facilities were undrawn.

HEI has a manageable maturity ladder, with just $10 million due in 2007. Hawaiian Electric has no maturing long-term debt until 2012. As of Sept. 30, 2006, HEI had $6.8 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents).

Standard & Poor's expects about three-quarters of Hawaiian Electric's 2006 construction program to be internally funded. Accelerating capital expenditures may necessitate a somewhat higher reliance on outside capital in 2007. In order to strengthen its balance sheet and support its capital program, Hawaiian Electric is not paying dividends to HEI in the second half of 2006. Importantly, ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows. The decrease in

Hawaiian Electric's dividend to HEI is expected to be partly offset by the increase in the bank's dividend. In the third quarter of 2006 the bank began, and plans to continue, to pay nearly all of its earnings as dividends to HEI while maintaining its target core capital ratio of 7.5% and still supporting its own business growth.

HEI has $50 million of debt capacity remaining under a Rule 415 shelf registration and $96 million remains on an omnibus shelf registration.

Outlook

The negative outlook on Hawaiian Electric mirrors that of parent HEI and reflects a subpar consolidated financial condition relative to the rating level. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaiian economy, a punitive final rate order, and, although not expected, a major erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit-supportive actions by the company as well as responsive rate treatment would lead to ratings stability.

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